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-1
and	)	
Implementation of Renewables Portfolio Standard Legislation	)	Docket No. 03-RPS-1078

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JUNE 30, 2008

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Reported by:
John Cota
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COMMISSIONERS PRESENT

Karen Douglas, Presiding Member

Jeffrey D. Byron, Associate Member

ADVISORS PRESENT

Panama Bartholomy

Kristy Chew

Laurie Ten Hope

Tim Tutt

CPUC ADVISORS PRESENT

Stephen St. Marie, Advisor to Commissioner Bohn

STAFF PRESENT

Joseph Fleshman

Mike Leaon

Kate Zocchetti

ALSO PRESENT

Anne Gillette, Energy Division, California Public Utilities Commission

Wilson Rickerson, Rickerson Energy Strategies, LLC

Robert Grace, Sustainable Energy Advantage, LLC

Gary C. Matteson, Mattesons and Associates

Carl Zichella, Sierra Club

Mary Lynch, Constellation Energy

Adam Browning, Vote Solar

ALSO PRESENT

Sean Simon, California Public Utilities Commission

Craig Lewis, Green Volts

Liz Merry, Verve Solar Consulting

Joseph S. Velasquez, San Diego Gas and Electric (SDG&E)

Kathy Treleven, Pacific Gas and Electric Company (PG&E)

Marci Burgdorf, Southern California Edison (SCE)

V. John Smith, Center for Energy Efficiency and Renewables Technologies (CEERT)

Laura Wisland, Union of Concerned Scientists (UCS)

Jacklyn Marks, California Public Utilities Commission

I N D E X

P R O C E E D I N G S

9:08 a.m.

MR. LEAON: Good morning and welcome. This is Mike Leaon. I am the supervisor of the Integrated Energy and Climate Change Unit in the Renewable Energy Office. I would like to welcome you to the staff workshop exploring the use of feed-in tariffs to expand renewable energy generation in California.

I do have a few housekeeping announcements that I would like to cover before we get started.

First in regard to WebEx participation. We will be using the WebEx system for online participation. If you are on the phone but not tuned in to WebEx please follow the directions on page six of the Workshop Notice to log in using WebEx. The WebEx system will allow you to view slides and ask questions during the Q&A portion of the workshop. All WebEx users are muted on entry, which means those of you on WebEx are muted right now. We will unmute you during the Q&A sessions. And I will talk more to this point in a moment.

Regarding housekeeping. We do have handouts available on the table on entry into searing Room A here. Restrooms are located across the atrium. As you exit the room they would be on your left, somewhat kitty-corner from the hearing room. There is a snack bar on the second floor. As you go up the main stairway here to the second floor you'll see it directly across the outdoor patio area.

Lastly, I do need to mention that in the event of an emergency to please follow Energy Commission staff outside. We need to exit calmly and safely in the event of emergency. We would gather in Roosevelt Park, which is across diagonally from the Commission building, across the intersection of Ninth and P.

And for those of you participating remotely. If you are viewing a webcast in order to participate on an interactive basis, again, you will have to log in using WebEx.

Regarding ground rules. We do ask that if you want to ask a question during the Q&A portion that you please fill out the blue cards. And you can turn those in to Commission staff to my right at the podium or at the laptop there. We will use those to allow participants to make public comment. We would ask that you come up to the podium and use the microphone to make your remarks. And also to provide a business to our court reporter to my left here. That would be very much appreciated.

And also if you could be sure to mute or turn off your cell phones.

During the question and answer portion of the workshop we will take questions in the order of the blue cards in the hearing room here. Then also through WebEx participants who can either click on the raise hand icon to indicate that you have a question that you would like to ask, and we will unmute you at the appropriate time so that you can ask your question. Or you can e-mail the host directly through the chat to indicate that you have a question.

For those that may be participating by phone only, we will try to allow some time to open the phone lines. And again that process, if you could wait to be prompted by me to ask a question we will attempt to get some questions in for those that are on the phone as well.

I do need to emphasize that we may not be able to get to everyone's questions today. So it's important that you also submit written comments to support any testimony that you would like to make.

And we are also providing a survey, an online survey took, which we hope to have available by close of business July 3, but no later than close of business Monday, July 7. And we will have our contractor speak to that tool in a little more detail. But we hope to be able to provide greater flexibility for those that want to make comments without having to go through developing detailed, written comments.

Concerning the agenda. This morning we will hear three presentations and we hope to have opening remarks from Commissioner Karen Douglas as well. We will hear from PUC staff this morning as well as Energy Commission contractors.

And we will have two feed-in tariff presentations. One, kind of an introduction to feed-in tariffs and also an overview of the use of feed-in tariffs in both Europe and North America.

Then we'll get into the nitty-gritty and the specifics of the challenges of using feed-in tariffs and a discussion of the Issues and Options paper.

We'll break for lunch at 11:45 and we

will reconvene at one o'clock.

After lunch we'll have a panel discussion in which our panelists will share their perspectives regarding the potential use of feed-in tariffs in California; followed by a brief break.

And then we'll have stakeholder comment time from 2:30 to four and we'll adjourn the workshop at four o'clock.

I would also like to briefly touch on the report development process. The purpose of today's workshop is, of course, to take stakeholder comment on the potential for the use of feed-in tariffs to expand renewable energy generation in California.

We will take today's comments and any written comments as submitted in support of today's testimony and use that information to help us revise the Issues Options Report. And that report will be considered at a second committee workshop on September 3. There will be another round of revision based on stakeholder comment from the September 3 workshop. And we plan to hold a third workshop in November and finalize the report.

The findings from the report will be used to help guide the 2009 Integrated Energy Policy Report.

We'd hoped to have opening remarks from Commissioner Karen Douglas but it appears that Karen has been delayed. So I think --

ASSOCIATE MEMBER BYRON: That's all right, you have another Commissioner here that would like to make some remarks.

MR. LEAON: I appreciate that, thank you very much.

ASSOCIATE MEMBER BYRON: Mr. Leaon, if it's all right.

As Mr. Leaon indicated, this is a staff workshop. Unfortunately, Commissioner Douglas is delayed. However, I fully suspect she will show up shortly and will make some remarks.

There's two committees that are really very interested in this. Commissioner Douglas chairs the Renewables Committee and I Chair the Integrated Energy Policy Report. We are very interested in this subject. And then, of course, Chairman Pfannenstiel serves as the second member on both of those committees.

I would like to just introduce, if I may briefly, at the dais this morning is Tim Tutt from Chairman Pfannenstiel's office. My advisor, Kristy Chew. But most important of all, representing the PUC, Commissioner Bohn's office is represented here today by Steve St. Marie.

The purpose, as you have indicated, in this workshop really stems from a number of recommendations that were made in the '07 IEPR, both short term and long term. And I know I am interested, and I suspect other Commissioners here at the Energy Commission as well are very keen on getting the public input with regard to this report and our recommendations.

We know that the Public Utilities Commission is extremely interested in this topic as well and there are some issues and concerns that they have. I hope that they will be voiced today. And Steve, I look forward to learning from the Commission. Not necessarily you but from other members of the Commission that are here today, what those concerns are.

I will stop there and ask if Mr. Tutt or Dr. St. Marie have any comments.

ADVISOR TUTT: I just would like to welcome everybody to the workshop. I'm glad that there's a lot of interest in this topic. You raised this in the last couple of IEPRs. And I wanted to suggest that we have a lot of interest in exploring the topic.

There's been no decisions made about directly going in this direction but we would like to explore the topic based on the success that we have seen in some of these feed-in tariff systems in Europe and elsewhere. So I am pleased to see the participation and interested in hearing the comments, pro and con, from all sides. Thank you.

CPUC ADVISOR ST. MARIE: Thank you. We at the CPUC are very interested in this topic. We have worked with feed-in tariffs on a limited basis for some time now and we intend to participate fully in this project. Thank you very much.

ASSOCIATE MEMBER BYRON: Good. Please proceed.

MR. LEAON: All right. Thank you for those opening remarks. Our first speaker is Anne Gillette with the California Public Utilities Commission. Anne is a analyst in the renewable procurement and resource planning group at the PUC. She works on long-term planning for renewable resource and transmission infrastructure and is the CPUC lead on the renewable energy transmission initiative. Anne's presentation will summarize the PUC's progress on implementing the renewables portfolio standard program. Anne.

MS. GILLETTE: Thank you very much. I am very pleased to be here representing the PUC this morning. And the purpose of my presentation is really just to give an overview on the RPS program. How we're doing both in procurement and product development. It will be fairly brief.

So in terms of procurement it appears that the RPS procurement process is working. The PUC has approved 95 contracts for almost 6,000 megawatts of new and existing RPS capacity.

Of those about 61 contracts are for new capacity, totaling about 4,500 megawatts.

If all this approved capacity were to come online by 2010 we would more than achieve our goal of 20 percent renewable energy.

Another indication that the procurement process is working is that the response to RPS solicitations has been very large and increasing.

(Commissioner Douglas and Advisor Bartholomy joined the workshop.)

MS. GILLETTE: The IOUs right now are finalizing the short-slit from the 2008 RPS solicitation. And it looks like they are going to short-list about ten times their incremental annual RPS procurement target. So we're seeing a huge response and enough good bids that they will continue negotiating with a huge amount of renewable generation.

As most of you know the RPS procurement process, as it is today, emphasizes competitive solicitations that lead to long-term contracts. And these long-term contracts are critical to getting project financing, is in turn critical to getting new steel in the ground.

This is just an indication, again, of the increasing interest in the RPS program. We're still working on compiling data from the 2008 RFO. But you'll see the 2007 is a huge increase in bids. Particularly the largest increase from solar, both solar thermal and solar PV. But there has been a wide range of different technologies represented in our solicitations and in the contracts that are subsequently signed.

Just another trend that we have noticed. RPS bid prices have been increasing and there are subtle factors that are contributing to this. One is that construction costs for all sorts of generation are increasing, both renewable and fossil.

But we are also seeing a shift in the resource mix. Again, going back to the previous slide. You will see that the largest increase in 2007, and what we have also witnessed in 2008, is from solar technologies.

And compared to most of the other technologies, particularly wind, which we have seen the most historically, solar has very high installation costs. It's a capital intensive technology. And so we're seeing higher prices on solar compared to, compared to other technologies. And because solar is taking up a larger percentage of the response we are seeing an increase, in general, in bid prices.

Another factor that is contributing is that many of our prime resource items have just been developed. There are several good sites in California that we are still trying to tap with new transmission. But the fact is that much of the lowest-hanging fruit in California has already been picked. California went out very early in developing its renewables and so to some extent we're kind of going up to the more expensive resources at this point.

There is also concern that constrained supply and policy-driven demand are driving up costs. This is because we have created a very large net-short. We have at this point in the short-term a constrained supply of renewable resources and that may be driving costs up.

So although procurement has been working, the project development itself has been slow. Only about 14 contracts for 400 megawatts have come online since the program began in 2002-2003. And to reach our goal of 20 percent in 2010 we need 3,000 megawatts online in the next two years.

Overall, RPS generation also hasn't kept pace with load growth. So you'll see this table breaks out RPS-eligible gigawatt hours by utility and then total, just for the IOUs. So this doesn't include municipal utilities.

But the total on the bottom shows total statewide RPS eligible gigawatt hours and then those gigawatt hours represented as a percentage of bundled retail sales. Which is how the RPS progress is actually measured. And you will see that overall we have actually decreased as a percentage of sales since 2003. Every year we have decreased. All of the numbers in red there indicate a year-on-year decrease, either in gigawatt hours or percentage terms.

Some of the low numbers in the past few years have to do with dry hydro years. There is a fair amount of small hydro that right now is part of the RPS portfolio so some of the low numbers recently have been due to that. But overall we are just seeing difficulties in project development of the new, the new contracts we have approved.

So to try to understand what is causing these delays in project development the CPUC staff go through, project by project, all of the contracts that we have approved for IOUs and we look at what the risk, what risks those projects are facing in two years and five years and ten years and we evaluate what the chances are we think they'll come online in the year they are actually supposed to.

We have put all of these project-specific risk ratings into an overall chart and so this represents of the contracts that we have approved, and some that are still under negotiation, the risks that these projects are facing to generation any given year. So a project might, for example, be red or yellow because of permitting difficulties in 2010 so it might show up in the red or yellow stack here. But we might think that by 2011-2012 those problems are going to be worked out so it might fall into the green category.

But you'll see -- We are not showing, we are not projecting as of this point that we are going to hit our 20 percent target in 2010. And we'll talk now about what risks those are that are causing these projects to be delayed.

So we've gone through, again, project by project, all these contracts we've approved and some that are still in negotiation, and identified what specific risks the projects are facing. Again, this is just 2010 generation. So this is a percentage of the 2010 RPS generation.

A very large percentage are affected by the PTC, the production tax credit and investment tax credit. This is something, unfortunately, we have very little control over. We can lobby in the nation's capital to try to get these tax credits extended but we have relatively little control. Some contracts would actually be cancelled if the PTC or the ITC isn't extended. Some have a delay built into the contract where they can delay until it is renewed. But it's causing quite a bit of risk.

The next category, not a big surprise again, is transmission. California's grid is constrained. And as many of you know, renewable resources are particularly constrained because they are often located far from load centers and areas where the grid isn't very robust. We have quite a few initiatives now to try to address this problem but it is, in the short term it is going to be a barrier to getting more renewables online.

We then have a host of other sources of risk including developer inexperience, difficulty getting financing, difficulty getting site control and various permits that are also creating risks for our projects. It's important to note that a project could have more than one source of risk so these don't add up to 100 percent. A project might be facing, might be at risk because of PTC but also at risk because of financing or because of transmission. So it could fall in more than one category.

Now that we have identified these barriers we are working to create multi-agency solutions to the known 20 percent RPS barriers.

The PUC oversees RPS procurement so we feel pretty confident that that process, as we discussed before, is working.

Product development, on the other hand, is the responsibility of a wide range of state agencies and entities. So we're trying to work with other agencies on addressing these problems.

In relation to transmission the PUC is responsible for permitting new transmission lines. So we have streamlined our permitting process.

We also initiated the Renewable Energy Transmission Initiative, which we are working very closely with the CEC, ISO and publicly-owned utilities on.

And we are working closely with the ISO on queue reform. The interconnection queue process is a major source of delay at this point.

And site control. Site control and permitting. We are in the early stages of trying to address these barriers but we have begun working with BLM and other relevant agencies to share information where it's appropriate to help them work through applications for leases, for example.

And in permitting we're anticipating working closely with the Energy Commission as more solar/thermal facilities are going through the permitting process. And again, sharing information and just trying to smooth those processes as much as possible.

So in terms of today's workshops we have just teed up a few questions here. We think it is important, given what we have talked about in terms of procurement working and product development and really being what we see as the barrier today. We think it is important to try to identify what is the problem that we are trying to solve with the feed-in tariff.

Is it a problem with the procurement process? With the project development process? And how significant are these problems? And then how would a feed-in tariff address these particular problems.

And finally, what challenges associated with implementation and administrative oversight might a new feed-in tariff create? We know that any new program takes quite a long time to get up and running, to work out all the kinks. So we need to think carefully about what sorts of new challenges a feed-in tariff might create.

And could those challenges outweigh the benefits of a feed-in tariff?

I am happy to take any questions at this point.

MR. LEAON: Thank you very much, Anne. I have one blue card. If we have questions for Anne in the room if you could fill out the blue card and bring those up that would be appreciated. The one blue card I have is Gary Matteson.

MR. MATTESON: I defer until the KEMA presentation.

MR. LEAON: Okay, all right.

ADVISOR TUTT: Mike, I have a couple of questions, if I may.

MR. LEAON: Okay.

ADVISOR TUTT: Anne, thank you for coming. Welcome to the Energy Commission. This is an important topic. We're glad to have the PUC here.

I had a question about your slide number four where you indicated that many prime resource sites have already been developed. Do you differentiate that conclusion or that assertion by resource type? And I think specifically I'm thinking of solar/thermal where we know there's a huge potential and there hasn't been a lot of development. And there might be others that are like that too.

MS. GILLETTE: Yes, I would entirely agree with that. What we are mainly seeing, for example, is in wind. We are seeing contracts coming in where the prices are higher because the capacity factor is lower. As I mentioned, there are some specific areas like Tehachapi where we think we are going to tap very good wind. But at this point many of the contract we're seeing have lower capacity factors and the prices are rising because many of the best sites have just been developed.

ADVISOR TUTT: So on the previous slide, Anne, you had a big increase in wind as well between '06 and '07. Is that where you are seeing the increase or is it in the -- Are there '08 solicitations out there that you're seeing the increases with as well?

MS. GILLETTE: Both, yes, yes.

ADVISOR TUTT: Okay, and the last question. On the slide about expected generation and risk, slide six. Just to have a better idea of how you're looking at this. And I like the way you have done this in your quarterly reports and incorporating risk into the projection of RPS energy. Where might the sterling contracts lie in these band of risks? Is that feasible to say?

MS. GILLETTE: No.

(Laughter)

MS. GILLETTE: Developers and utilities are understandably very nervous about our supporting this sort of information. The last thing that we want to do is say something about a project that is then going to actually increase its risk by reducing its chance of getting financing, whether we say it is at risk because of permitting or transmission or anything else. So we only report these numbers on an aggregated basis and we don't break it out by contract.

ADVISOR TUTT: Okay, thank you. I did have one last question on the next slide, your barrier slide. I may have missed it. Did you say how you acquired this information?

MS. GILLETTE: I didn't mention that. As a result of a PUC decision we get biannual project status reports from the utilities on all of their, all of the RPS contracts that we have approved as well as some projects that are short-listed. So we are constantly updating and tweaking that spreadsheet so that we get very detailed information that will allow us to do this sort of analysis.

So we ask for, you know, specific permits. You know, how far the projects are in the permitting process. Exactly what substation they are going to interconnect to and exactly what upgrades they would need and exactly what permits they would need for those upgrades. So we really try to get a realistic view of their online date as well as the sorts of risks that they're facing.

And then we also have just -- The PUC has appointed three contract managers within the RPS staff so we have one contract manager for each utility. And they are in constant conversation with the utilities about the status of the projects. So we have those biannual reports and just an open flow of information during the rest of the year.

ADVISOR TUTT: Can you tell me whether collaborative staff here has access to that information.

MS. GILLETTE: I don't know that there has been a request. Assuming the confidentiality of the information would be protected I think it could be shared. I don't know that that's been discussed in the past.

ADVISOR TUTT: Thank you.

MS. GILLETTE: And there are -- There's a public version of those reports that's filed to the RPS service list but much of the confidential information is redacted. Any confidential information is redacted. But we could talk with the Energy Commission about sharing that.

MR. LEAON: Okay. Before I ask for blue cards are there any more questions from the dais?

Okay. All right, we do have a couple of blue card questions for you, Anne.

MS. GILLETTE: Okay.

MR. LEAON: Carl -- I'm sorry, Zicheria? I apologize if I butcher your last name there.

MR. ZICHELLA: Give it a shot, go ahead.

MR. LEAON: Zicheria.

MR. ZICHELLA: Zichella, thank you.

MR. LEAON: Zichella, okay.

MR. ZICHELLA: Before I begin, I see Commissioner Douglas is here. Do you want to make an opening, some remarks?

PRESIDING MEMBER DOUGLAS: No, please continue.

MR. ZICHELLA: Great. Good morning, Anne.

MS. GILLETTE: Good morning, Carl.

MR. ZICHELLA: On slide nine in your presentation you have some key questions about feed-in tariffs. I know that the Public Utilities Commission has explored the idea somewhat. I wonder if you could describe the program that the PUC has already been trying to implement. And if you have answered any of these questions for yourselves, like if you have thought about these questions with respect to your own program, if you could give us some insights.

We know that in Europe feed-in tariff programs have been very powerful, especially for distributed generation. I was just wondering if you could give us some insight into what the PUC has learned in their efforts so far.

MS. GILLETTE: Okay. I assume the feed-in tariff you are referring to is our small, the one to one and a half megawatt feed-in tariff we have. We agree that for small facilities there are definitely transaction costs to participating in the RPS solicitation process.

So we understand that for small facilities, perhaps less than 20 megawatts, less than 5 megawatts, whatever size, there can definitely be a benefit to having some sort of standard process so they don't have to develop a full bid, participate in the large RPS solicitation as a 100 megawatt facility would.

As far as a feed-in tariff for larger than that. I understand this workshop is looking specifically at over 20 megawatts. We really just look forward to the conversation today.

We are not -- As discussed, we think that the largest barrier that we are facing right now is project development and so we are specifically interested in how a feed-in tariff might help address that problem since we do see that as being the biggest challenge right now to RPS procurement. But we are not experts on feed-in tariffs and we look forward to the discussion and to the panelists addressing these sorts of questions throughout the afternoon.

MR. LEAON: All right, thank you, Anne. One more blue card question from Mary Lynch. If you could come up to the podium.

MS. LYNCH: Good morning. My question is just a very quick factual question. And Anne, it's whether you have had any updated on the status of the PTC issue at the federal level and whether it's looking to shape up? Is it looking more like a risk or is it looking like it's getting, moving towards resolution?

MS. GILLETTE: I unfortunately don't have, don't have an update on that. As I understand it's set to expire at the end of this year. And we already have some projects that might be exercising termination clauses soon this year because they don't expect, they don't expect to be able to come on line by the end of this year, which would be required to get the credit. But I don't know the latest status on legislation.

MS. LYNCH: On whether it's getting extended or --

MS. GILLETTE: I know that some has been proposed. I am not sure whether it's still in committee.

MS. LYNCH: Okay, thank you.

MR. LEAON: Okay, let me check with staff. Do we have any WebEx participants?

MR. FLESHMAN: We don't have any WebEx questions. I can unmute the phone lines in case.

MR. LEAON: Okay. Before you unmute the phone lines. For those of you that may be participating over the phone please be sure to put your phone on mute now and only unmute your phone if you want to ask a question. So with that, Joe, go ahead and unmute the phone lines and let's see if we have anyone on the phone.

MR. LEAON: Okay, it sounds as if the phones have been unmuted. Is there anyone on the phone that would like to ask a question?

(No response)

MR. LEAON: Okay, hearing none I think you're off the hook, Anne.

MS. GILLETTE: Thank you.

MR. LEAON: All right. Thank you very much for your presentation.

Before we move to our next presenter I would like to ask if Commissioner Douglas would like to make any remarks.

PRESIDING MEMBER DOUGLAS: No, thank

you.

MR. LEAON: Okay, thank you. All right, if we could put the phones back on mute. We'll move to our next presentation.

And our next presenter is Wilson Rickerson with Rickerson Energy Strategies. Wilson is a Boston-based consultant focusing on renewable energy policies and markets. His current work includes research on comparative renewable energy policy in the US and Europe, including feed-in tariffs and incentives for renewable heating and cooling. He holds a masters in energy and environmental policy from the University of Delaware.

Wilson's presentations will focus on what constitutes a feed-in tariff and the past and current use of feed-in tariffs in Europe and North America. Wilson.

MR. RICKERSON: Thanks very much. Good morning, everyone, it's great to be here. It's been a very interesting 12, 24 months. I started out back in Germany in 2001 working for the German Wind Energy Association and feed-in tariffs were very, very much on the radar but they had just changed over to their new 2000 law and the market was just starting to take off.

I came back to the United States in 2002 and no one had really even heard about feed-in tariffs. Some people thought it had something to do with agriculture and feeding animals. Because it is a very, it's a pretty awful translation of the German word, Stromeinspeisungsgesetz, which means electricity feeding-in law. We have just kind of kept that awkward translation as we've gone along.

But as we will be going through today, we will be kind of surveying what is going on in Europe but also what is now happening in the United States. In addition to California we have seen about six states considering legislation, about eight other states seriously talking about legislation. And also as of Thursday there is now a federal feed-in tariff bill.

But we are going to kick things off today, right now I guess, with a survey of what people have said out there, what some of the opinions are, why we are here today of what makes feed-in tariffs compelling, what they actually are. The fact they are not a panacea, there are design risks and limitations and where we could trip up if we try to implement them. And then we'll move also into definitions of what a feed-in tariff is, where we are using it, et cetera, et cetera.

Just as a little bit of background. As most of you are probably aware in 2007 the IEPR directed the Energy Commission, in collaboration with the CPUC, to explore feed-in tariffs for projects over 20 megawatts. With the explicit goals of creating more -- Incorporating the value of a more diverse renewable energy mix.

Also explicitly exploring the features of successful European feed-in tariffs.

And ultimately preparing a white paper on feed-in tariffs in 2008.

There is a paper out front which is kind of a draft of issues and options I believe we'll be working more on as we move through the year on rounding out a more comprehensive feed-in tariff white paper.

So what are some of the reasons we have heard as we were doing our survey of why feed-in tariffs could fit within the California context? One of the reasons we discussed is because of the various market barriers that we have seen in different reports, be it the IEPR or other reports from different stakeholders.

We just walked through many of them very briefly. Permitting and siting. Contract failure. Site control and financing. Lack of transmission, as we mentioned with a lot of our solar resources. Developer risk. The perceived complexity of the RPS solicitation process. And the suitability of the current solicitation process for smaller projects. Are smaller projects actually falling through the cracks of our current RPS solicitations.

And also the problem of, if under a competitive bidding situation, if you submit a bid and over a period of months before you were finally able to finalize your contract the costs change, are you left with a contract that you can no longer execute on. What happens when some of those contracts become infeasible. So those are current market barriers.

What, if anything, is a feed-in tariff? There are a lot of different definitions and we will be unpacking that definition over the course of the day. And the paper out in the lobby also does that as well. There is no one, set definition. But in general it's a long-term, either a contract or a payment, with a specified term and a fixed price for eligible generation. It's basically, if you build it, we'll buy it at whatever price we specified and however we've decided to structure that contract or that payment.

Also it's a standing price schedule so you know in advance what price you're going to get to provide some certainty for developers.

And also, generally it's available to all eligible generators from the interconnecting utility in which they are actually building their projects.

The key features of feed-in tariffs. Number one, a guaranteed price. I know how much money I'm going to get from day one.

Secondly, a guaranteed buyer. If you know someone is going to buy it from you it eliminates issues of market timing. It's basically a standing contract where you're not bidding for it, you can just enter into it.

It's a long-term, guaranteed revenue stream, which obviously improves investor confidence. We will be getting into that more, into how that dynamic impacts risk premiums and ultimately ratepayer impact.

Generally speaking it's unbound. Especially in Europe it's kind of an open hunting license. So you build a project, no matter how big, no matter where, you get that tariff and there's no cap on how much energy or electricity they will ultimately accept into the feed-in tariff program.

Because it's a standard offer there are comparatively low transaction costs.

Also comparatively low administrative complexity. There aren't any tendering RFPs, et cetera, et cetera to deal with.

Also the reason that they're called -- and sometimes you lose sight of this. But again, referring back to that awkward German word. The key to it is feeding-in. And that's because the feed-in tariffs, one of the main emphases was on guaranteed interconnection. If you build a project you can definitely feed your electricity into the grid. And we since layered on top of that a lot of things like guaranteed price, long-term contracting, et cetera, et cetera. But the kernel of feed-in tariff is guaranteed interconnection.

And finally. Again this gets into the design criteria, which we will explore in much greater detail later. It can be differentiated by technology. So, for example, some feed-in tariffs are structured to make each technology type profitable. So PV would get a specific feed-in tariff designed to make it profitable, wind and so on and so forth.

Or there are other ways you can differentiate feed-in tariffs to target specific resources by type, by size, by resource quality, by vintage, how old they are, and by ownership structure, be it community-owned or not community-owned. And again, we'll be unpacking those in just a little while.

Of course feed-in tariffs, while we think they -- Many people think they're great. We have heard a lot of folks advocating for them, especially in the last 24 months in the United States. They do have their limitations. They are not a fix for everything.

A lot of these problems, on this slide anyway, are interrelated. The fact is, if you open up a standard offer contract you are not sure how much power, how much capacity is going to drive through that contract. And so you have an unknown policy cost overall because you have an unknown quantity. In Europe they have targets for their feed-in tariffs. You know, ten percent by 2010 let's say. But if you break through that ten percent target that's just fine, keep going. It's more of a target than a limitation.

Another issue is, you know, depending on what kind of market structure you have that raises some considerations we'll get into later. Who is a reasonable buyer for the electricity? Especially under an unlimited, open-ended, standard offer.

There's always the risk that we hear repeatedly raised of overpaying and underpaying. If you are making a political determination about a price how do you know you've got that right.

Similarly related to that is that can either overstimulate or understimulate the market depending where you put that price point.

And obviously, just setting an open-ended tariff doesn't solve underlying issues related to transmission, and oftentimes permitting and siting. And we have actually seen that play out in Europe. If you haven't solved those two issues a feed-in tariff really doesn't go very far.

A few of the design risks. If you set a price is it going to be able to react to the market. You can build a feed-in tariff that doesn't change ever. And as a result, if market prices fluctuate up and down, if there are market efficiencies and you have an unresponsive tariff rate, then you could have a problem. Especially with ratepayer impacts.

You could have the unintended consequence of favoring less-efficient plants. I say that because it's unintended. Because in some European markets they structure their feed-in tariffs specifically to target less-efficient plants.

In Germany they have got wind up on the coasts. Not to the south. They want wind throughout the country. So they have actually got feed-in tariffs favoring feed-in tariffs in less windy resources in order to get greater geographic distribution. To some folks in the United States that sounds like a perverse way to do things but in fact that's one of the cores of their policy making.

You could also have unequal cost allocation. We have definitely seen that in Europe. You would have to repair that if you don't have a good, competitively neutral cost redistribution scheme.

And finally, if you do have a cap for your feed-in tariff, as you have seen a lot of other capped programs that are very attractive. You could have speculative queuing. Which means, I'll put in a project that I may or may not think will actually work at this price just so I can reserve my place in line. And again we'll get to that later.

But on the other side. Feed-in tariffs might. The great ideal. Why do we care about them? What might they do? Again, not necessarily but what might and why do we find them compelling?

First, they can reduce risk. In fact, in Europe they have reduced a lot of risk and we'll get to some EU analyses of how that's played out in terms of costs. Without necessarily increasing ratepayer costs. Especially when you're dealing with near-market resources and standard offer contracts. And that's especially relative to a viable cost benchmark, i.e. projects that are going to work. Not necessarily to the cost benchmark of projects that might have been speculatively bid and probably did fail.

Also you can reduce developer costs by -- Actually, by reducing developer risk you can also reduce developer costs. And of course reducing the complexity of the entire process in general. That lowers -- Giving someone let's say a 20 year fixed-price contract they can count on. That reduces the cost of capital they might get from their financiers, which also reduces transaction contracting costs and security requirements potentially.

Along with that, as we mentioned earlier, it could reduce utility, CPUC and CEC administrative costs and burden. Especially if you've got a standard offer contract. You can just kind of -- You can open up and let go.

It also can, depending on how its structured, provide a viable market for smaller projects or for certain technology types that might otherwise fall through the cracks from the larger solicitations. And I do understand that today the general focus is on above 20 megawatts.

But there's probably going to be an opportunity to talk about a broad range of things here at today's forum.

Feed-in tariffs might, part two. A few of the things we've heard is that, again, by reducing risk there's a possibility to reduce the potential for RPS contracts to become infeasible while permitting and siting or transmission issues are being resolved.

If you've got a project with a 20 year guarantee, perhaps your cost of capital and your financing is going to come down. That gives you a little bit more headroom to absorb things during the project development process like changing material costs, changing energy prices, et cetera, et cetera.

And that also increase the willingness of developers to invest in other things like siting and permitting. So although feed-in tariffs may not have a direct impact on every single -- on things like siting and permitting, they could have at least indirect benefit.

So why should, why could California consider feed-in tariffs. This is, again, a survey of opinions that we have seen during the past several months. We have been leafing through different regulatory proceedings going back to 2006 and before. There's certainly different perspectives on this, obviously.

But number one, the state may or may not be on track to meet its RPS requirements by 2010.

And also the 33 percent by 2020 goal may be problematic if markets can't be nudged to move faster.

Another compelling issue, why do we care about this? Feed-in tariffs, frankly, have driven very, very expansion of renewable markets in other countries. I think the question for today moving forward is, is how they've driven it useful or worthy of being copied over here.

Another interesting wrinkle was that the current MPR pay actually set a price floor above the cost that some renewables can be profitably developed. So let's say you've got a standard offer that were below the MPR. That might give some developers a certainty to develop projects they might otherwise just say, okay, well the MPR is a nice price floor, I'll just use that instead.

As we also mentioned before, feed-in tariffs may actually help reduce the contract failure rate.

And they can also be used to facilitate renewable projects in areas with new transmission once the transmission gets built.

Another reason we have seen talk about feed-in tariffs here in California is because we have already been experimenting with them here to some degree.

As we heard from our colleague from the CPUC, there was both AB 1969 in 2006 that established up to 1.5 megawatt standard offer contracts for renewables sited at wastewater and water facilities.

These are priced at the MPR. But it's a time of value MPR, which we'll be discussing in a little bit.

And that particular bill had a cap of 250 megawatts statewide.

In 2007 the CPUC ordered an expansion of that cap to 478.4 megawatts of renewables statewide. Again priced at the MPR. And expanded it just from wastewater and water facilities to all renewable customers.

And the CPUC is currently soliciting comments on expanding that feed-in tariff beyond

SCE and PG&E where it's currently limited. And expand the project cap up to 20 megawatts from 1.5 megawatts.

As we'll talk about later, we have seen similar legislation proposed in the California Legislature to also expand and broaden that particular set, the current feed-in tariff regulation.

And also through the end of this year SCE has a standard contract available for biogas and biomass generators under 20 megawatts, priced at the 2006 MPR.

So in general we have seen several different policies already on the table here in California in the last two years that tend to be technology-neutral and based on MPR, but falling under the rubric of feed-in tariff. And we'll try to discuss -- we'll be discussing how that feed-in tariff compares to others that are out there.

So switching over from the contacts and survey opinion that we have encountered during the past couple of months to what's actually happening out there, both abroad and here in the United States.

Internationally, according to the REN 21 survey of Global Renewable Energy Policy, feed-in tariffs of some form or another are the most globally prevalent, renewable energy policy at the national level. We certainly have seen a heavy penetration of feed-in tariffs in Europe.

In North America we have seen variations in both Ontario and Prince Edward Island.

And then feed-in tariffs have also moved markets relatively rapidly in both Brazil and South Korea.

Just looking at -- We always show RPS maps. And I will be showing some RPS maps by the way, so look out. We always show RPS here in the United States. And this is kind of a map of European policy. The dark gray states -- countries are those that actually have some form of feed-in tariff currently in place. There are 18, or the large majority of the EU member nations.

Those in gray have some form of tradable green certificate program. And there's been a big fight over in Europe between long-term contracting and tradable green credits.

Then a few other states have different variations of hybrids and tax incentives.

But generally speaking, feed-in tariffs dominate in Europe.

In 2001 the European Union said, okay, every country needs to -- here is your target. You get to choose which mechanism you want to get to that target. And in 2005 we are going to analyze and see which one actually worked. And we're going to try to harmonize across the board and say, okay, that was the best so we're going to use it.

The majority of the EU countries actually chose some form of feed-in tariff.

And the three most successful that are out there have been Denmark, Spain and Germany. But again, as we are walking through today step by step, although we call these things feed-in tariffs, all three of them are distinctly different. They use different mechanisms. And the devil will ultimately be in the design details for California.

Starting off with Denmark. Here we go. So Denmark actually -- its market has cooled off to some degree. But back in the early '90s it established a feed-in tariff pegged at retail. So it's 85 percent of the retail rate. And it was technology neutral and open to all generators. that drove Denmark to a market-leading position in wind energy back in the '90s.

But then they attempted to switch to a tradable credit system in 2000. Their market collapsed. As you can see their wind has kind of bounced along a little bit and flatlined in 2003, 2004, 2005. And they have yet to recover.

But they did actually set a mean pace early in Europe that some kind of standardized contract could work to drive markets. And they're currently up to, I think, 20 percent wind penetration in Denmark on a normal day. And much, much, much higher when the wind blows hard.

Spain took a different approach. They instead of setting a long-term standard contract for a fixed price, they have got a fixed premium or an adder. Kind of like the PTC but not tax-based. It's actually cash-based that floats on top of the spot market.

That adder is again -- Unlike the Danish feed-in tariff, which is technology neutral, this one is technology specific. So every single technology got its own adder. Small hydro got about two cents, solar-thermal electric got about

30 cents riding on top of the spot power.

They also, in addition to that, market with an adder on top. Like my PowerPoint image there. In addition to having this they also have a separate feed-in tariff that you can switch to, which kind of serves as a price for that market. So if your spot market power plus adder sinks too low you can jump to the separate feed-in tariff. But so far no one has opted to use that because electricity prices have been going high.

Wind and PV markets, as most folks are aware, have experienced extremely rapid growth in Spain.

And some in Europe have also argued that that form of having an adder on top of the wholesale prices market is more compatible with the electricity market because it sends market signals to generators.

On the other hand, prices have tended to go up and up and up in Spain so they have kind of foregone the option of using a feed-in tariff as a hedge. Under some fixed price feed-in tariffs, if you set a 20 year contract and someone jumps on that and electricity prices go much, much higher, and you're locked into that rate for 20 years and when you've got an adder on top of wholesale prices, that probably is not going to happen.

So the premium approach with the adder does put the potential hedge benefit at risk, even if does have some market based options built into it.

Germany is the third option we'll walk through. I'm sorry, the third country we'll do a quick overview of. Like Denmark, they started out with a retail peg in the 1990s and experienced extremely rapid wind growth.

But then retail prices sagged. The market sagged with it. And they switched to the now-famous German feed-in tariff where they set prices for each and every individual technology based on what that technology would need to be profitable, for 20 years.

And also as I mentioned earlier, they also included something whereby Germany, a relatively windless country. You've got a higher feed-in tariff rate for a longer period of time if your wind project was in worst wind resource. As a result they now have something like 20,000 megawatts or more of wind power in the United States. I'm sorry, in Germany. Which is much more than the United States.

Then in 2004 after extremely rapid market growth they amended the feed-in tariff once again to even further stratify technology. so instead of having a PV feed-in tariff they have one for small PV, middle-size PV, BI PV, field-mounted PV. And they got more and more specific and then blew up a lot more of their markets in different ways. Now they are the world's largest PV and wind energy market.

And also their biogas market recently has exploded. It doubled since their 2004 feed-in tariff revision, doubled in the past three years. And nationally anyway, Germany's electricity has increased from about 6.5 percent in the early 2000s to about 14 percent in 2007.

Their EU target was 12.5 percent in 2010. So they are already above their target by a long shot, three years ahead of schedule.

Also interesting to note. According to a German federal analysis, they have actually saved money on their feed-in tariff. As you can see the costs above. There's an incremental policy cost of the feed-in tariff and things like the extra electricity that they had to balance the incremental resources. And also the transaction costs and the administrative costs of the feed-in tariff were about 3.3 billion in 2006.

However, they have a competitive market and their spot market prices have been fairly, A, volatile, and B, high. And because their feed-in tariff resources move through on a month-ahead schedule, large tranches of renewable energy resources moved into the market and significantly cooled spot market prices for an estimated savings of about 5 billion dollars (sic).

In addition to the import savings of about a billion. And then the mitigation of external costs of about 3.4 billion. So for total savings, about 9.3 billion, versus the total cost of about 3 billion.

Are there implications in that for the US market? maybe, maybe not. Also, will this continue to happen? Also maybe, maybe not. But still a very interesting analysis to consider.

Europe. We mentioned earlier that the EU in 2005 decided to analyze where costs, where different policy costs are. Very briefly. We've got a bunch of red dots and blue bars up on the screen. The red dots -- and different countries across the bottom.

The red dots are what people actually got paid. The blue bars is what they needed to get paid. In some countries they got paid more than they needed. In some countries they got paid right about what they needed.

And what surprised people and what surprised the EU is that the countries that have tradable credit regimes, like the UK and Italy and Belgium, are the ones with the dots above the bars. In other words, tradable credits were trading well above what developers needed to be profitable.

And the reason for that, according to the EU, was risk. Because basically investors looked at a 20 year variable stream of revenue and they said, that's pretty risky. Therefore my interest rates are going to be higher, project costs are going to be higher, and in general the market is going to trade higher than it would otherwise.

On the other side, in countries where they actually politically set the prices, generally speaking, the red dots are within the bounds of reason within the blue bars. Which led the EU to conclude, as you can see across the top, that feed-in tariffs generally achieve larger deployment at lower costs than policies that have more inherent risk in them. I guess it's one thing you could say.

All right. So does that again -- What's that, Bob? Keep moving? I'm going to keep moving. So is the European experience relevant in the United States? They have enjoyed rapid market growth.

Their policy is not necessarily inherently superior to ours in that there are different market conditions. you can have poorly built feed-in tariffs, you can have well-built feed-in tariffs. And also superiority is ultimately based on policy objectives. And that will be part of the process today is to find what those are.

In general, however, unlike in Europe, it is not necessarily a head-to-head clash of RPS versus feed-in tariffs. you can use feed-in tariffs to meet RPS goals. And ultimately, the devils is in the design details.

Moving now to a rapid review of feed-in tariffs in North America.

Most of you are aware that Canada had one. They still have one but as of May 2008 they actually limited it back to under 10 kilowatt systems. Because, frankly, market growth was a bit too fast for some folks up there. But they didn't have PV at 42 cents a kilowatt hour and wind at 11 cents per kilowatt hour.

Prince Edward Island has seen a much smaller feed-in tariff. About 5.75 cents per kilowatt hour, technology neutral. It's had a few things in there but not quite as much as Ontario.

But in general we haven't directly referenced those two states, those two provinces in our policy-making experience here in the US.

In the US we live in the shadow, to some degree, of PURPA for better or for worse. Most of you remember the Standard Offer Number 4 here in California and also New York State's Six Cent Rule. These were long-term standard offer contracts based on definitions of avoided costs. In the case of Standard Offer number 4 it was based on projected future oil prices. So that was then.

Now we generally haven't seen PURPA-like mechanisms in the United States for about 20 years. We have seen a broad proliferation of different state policies with different state policy mechanisms.

Here is the current patchwork across the United States. Twenty-six states with some type of policy objective. We generally call them RPS. Another six states with voluntary goals. But this process has been -- A, occurred very rapidly, and it has been iterative. We have seen a lot of change in these goals. It's hard to say, here is one definition that catches what RPS means in the United States.

Over the past 24 months we have seen 19 states either introduce new legislation entirely for RPS or significantly expand and alter their RPS legislation. We started out with tradable, renewable credit regimes in the Northeast and Texas. As we progressed west across the country you have seen different types of mechanisms.

And with this new round of changes, if you have all seen the LBNL report that came out recently an RPS review, there are two trends, two distinct trends in where RPS policy making seems to be going.

Number one, technology differentiation.

We started out with New Jersey saying, we want a PV tier. And then North Carolina said, we want a PV tier, a hog waste tier and a chicken waste tier. And now New Mexico has a tier for everything. That starts to look a bit more like feed-in tariff design choices when you're making specific choices about specific technologies.

Secondly, we've seen a trend towards long-term contracting or these other mechanisms to take some of the volatility out of tradable credit regime markets.

Again, if you're starting to differentiate by technology, and you're starting to try to take some of the volatility out of the markets, is there some -- Do you start to see best practices that you can look over to Europe for to then apply in the United States.

Which then brings us to this slide which is current states in the United States having either past introduced or are considering feed-in tariffs. As you can see almost every single one of these with the exception of Florida and Michigan are in states that already have some kind of renewable target.

So it's not -- I just point that out

because they are not necessarily at odds. These are states looking not necessarily to address problems with their current policy-making but to say, how can we supplement current policy making and achieve some discrete policy objectives that may not be already captured in our other RPS.

What are some of these. Michigan, Illinois, Rhode Island and Minnesota have all introduced bills very similar to the European philosophy of lay out technology-specific prices for PV, for wind, et cetera, over 20 years.

The contracts tend to range between 8 cents and 14 cents for most near-market resources and about 48 cents to 71 cents for PV. The principal innovation among these that sets one apart from the other is that Minnesota has almost the exact same law as the other states or proposed legislation, that means it passed. But it has to be community-owned in Minnesota.

In Hawaii we have seen four separate bills that include 20 year contracts for PV. They range from 45 cents in one bill to 70 cents in another bill. Different in that 100 percent of the electricity being fed into the grid, like in the Michigan model. In Hawaii this is kind of net metering on steroids. You get that rate for the excess you feed into the grid.

Of course we have seen them in California. I thought this was interesting. I'll just quote briefly from the CSI proceedings where PG&E said that it:

"-- supports consideration of a feed-in tariff as a potential solution to the current tension surrounding -- various subsidies supporting solar generation -- The various incentives including the CSI and net metering could be combined into a single incentive structure that declines over time."

So since even the CSI proceedings we have had talk of some kind of feed-in tariff in California.

We have seen that progress a little farther with AB 1969. The 2007 IEPR.

But then looking beyond what we've currently got in front of us. In the Legislature we have seen bills that would amend the current CPUC feed-in tariff. We have seen -- We have seen one that actually tried to set prices but was then amended to not said prices and said, defer that process to the Commissions.

And finally SB 1807 would actually require the CPUC to set prices based on generation costs rather than being technology neutral.

So we have seen and are seeing the continuation of a lot of feed-in tariff talk in California, both in the Commissions and the Legislature.

In terms of who is doing what kind of analysis in the United States. Not much has actually been done. The only one thus far is in New Jersey where they were trying to find a way to transition from rebates for solar to some kind of performance-based mechanism.

And this is, very briefly, it's a good beach read. About 100 pages of report about different models that are out there. They concluded that the 15 year tariff model in New Jersey would have the lowest ratepayer impact of all the models they looked at. Again, just as in Europe, in a parallel analysis to Europe because of the risk premiums inherent with tradable credits. But so far that's been about the only one.

Some preliminary things have been done

for Rhode Island which are very interesting but they haven't yet been published.

Also as of Thursday we now have a federal feed-in tariff that's been introduced. This was introduced by Congressman Jay Inslee, co-sponsored by Congressman Delahunt and others. It would establish, A, again back to the original definition of feed-in tariffs, standardized interconnection across the United States for renewable energy facilities below 20 megawatts.

Twenty-year fixed-price contracts.

Uniform national rates for different technologies, differentiated by technology and facility size.

Just as we have seen in Europe there would be a national cost redistribution mechanism but it would actually be based regionally. So you wouldn't have the Southeast worried that there would be a large wealth transfer to other parts of the country. And that would be managed through a FERC-overseen public/private organization called the RenewCorps.

So that's out there. It would be interesting to track and see where that flag, now planted, actually gets moved to.

I think that's about it. Thanks very much for your attention and I'm sorry if I'm over time.

MR. LEAON: No problem. Thank you, very much, Wilson, for that very thorough analysis. I see we have staff in the back of the room, if you could help expedite the blue card process by handing out and collecting blue cards that would be very helpful. And while that process is going on let me ask if we have questions from the dais.

ASSOCIATE MEMBER BYRON: First of all, thanks for the explanation of the German origin of the feed-in tariff, that was very helpful.

An excellent presentation. A lot of great information here. And don't worry about going over.

MR. RICKERSON: Thank you.

ASSOCIATE MEMBER BYRON: I think this is exactly the kind of information we are looking for. Are you familiar with the solicitation process and how we procure renewables here in the state of California?

MR. RICKERSON: I would say yes, tentatively. I am certainly not as familiar as some of the other stakeholders in the room.

ASSOCIATE MEMBER BYRON: Sure. But given your experience and knowledge of how all the other countries have been doing feed-in tariffs would you care to comment on that procurement process and does it affect what we are trying to do here?

MR. RICKERSON: Would you mind clarifying the question.

ASSOCIATE MEMBER BYRON: Sure. If you are familiar with our procurement process.

MR. RICKERSON: Yes.

ASSOCIATE MEMBER BYRON: The way it's done with each of the utilities through procurement review groups and non-disclosure agreements and confidential information. Does that affect our ability to do -- to have an effective feed-in tariff?

MR. RICKERSON: As in, if we preserve the current procurement process could we also have an effective feed-in tariff?

ASSOCIATE MEMBER BYRON: Yes.

MR. RICKERSON: I think that's part of what we'll be getting into today. I think it ultimately goes back a lot, again, to your policy objectives. And we are kind of walking through the different, the 15 or 16 or so different design choices that you could make.

There are a lot of -- There are some very, very fundamental differences between the European and what is currently in place in California. I think it would be a bit early for me to say, well of course you could do X, Y, Z in California without having spent the day listening.

So other things have been moving very, very quickly over there and there isn't a central procurement process necessarily in terms of, you know, bidding and tendering. There is just a general standard, an open-ended standard offer contract and they have let the markets just go.

ASSOCIATE MEMBER BYRON: Okay. Thank you.

MR. LEAON: Any other questions from the dais?

ADVISOR TUTT: Sure. If I could follow up on that line of questioning for a little bit. If you look at the Nicholas Stern results in your presentation.

MR. RICKERSON: Yes.

ADVISOR TUTT: The description there was that the dots that are above the blue ranges of cost were due to risk involved in those markets or those countries which were depending primarily on REC markets.

MR. RICKERSON: Correct.

ADVISOR TUTT: In California, of course, we have primarily long-term contracts for renewables. That seems to take out some of that risk. Would you comment on that.

MR. RICKERSON: Sure. I think that's actually an earlier, it's an earlier dialogue that the Europeans had. If I'm looking over to European experience. Before they had this knockdown, drag-out fight between tradable credits and feed-in tariffs they had one between tendering and bidding and feed-in tariffs. And generally countries like the UK and Ireland and France and a few others that had, previously had tendering, ultimately abandoned those systems as being less effective in comparison.

But whether that is easily transferrable over here. I think -- That those lessons are easily transferrable over here I think remains to be seen. There are a lot of differences between how the Europeans did their tendering and how California has been doing theirs.

Generally speaking, though, I think that long-term contracts probably have less risk than some kind of tradable revenue stream -- tradable credit stream, no matter which way you cut it.

ADVISOR TUTT: You described feed-in tariffs as having an unknown cost because it was an unknown quantity of resources that might sign up.

MR. RICKERSON: Right.

ADVISOR TUTT: So specifically how in your mind would that square with California's law requirement that utilities achieve 20 percent by 2010 and the goal of 33 percent? I know that European countries have that target.

MR. RICKERSON: Sure.

ADVISOR TUTT: Or targets as well. But if there is an unknown quantity how can we be assured our targets are met?

MR. RICKERSON: I think it is a matter of how you ultimately define those targets. If they are aspirational targets and you get there when you get there and if you even exceed them to a slight degree and that's great, then I think that's a policy choice you make.

If you then introduce a cap that has an

implicit hard stop to it, then that obviously has implications for the market. You get into queuing and things like that.

In a way Europe looks a lot like the United States in terms of there are a lot of countries, just like we have a lot of states. The Europeans might cringe to hear me say that so I'm not on record.

(Laughter)

MR. RICKERSON: But in the sense that they all have, you know, certain percentage by a certain date targets over there. We've got certain percent by certain targets -- certain percent by certain dates over here. We have a lot of different mechanisms to get there.

Some of their targets have implicit hard stops in them and some of them like Germany, hey, if we blow through great. The Germans just said, now that they have moved so quickly on their original EU-set target they have set 25 percent targets by 2020 and 45 percent targets by 2030.

ADVISOR TUTT: One last question, if I may. You talked about the potential for RPS contracts to become infeasible while permitting and siting or transmission issues were being resolved. And I guess I'm wondering how that fits with feed-in tariffs. I mean, if you have a feed-in tariff system in place the project developer still potentially has permitting, siting and transmissions issues. They might start working on those and by the time they get to where they are eligible for a feed-in tariff they realize their cost structure doesn't work anymore. Is that true?

MR. RICKERSON: I guess I should walk through a bit more step-by-step than I did. I think I might have rushed that pat during my presentation. I don't think the feed-in tariffs address transmission planning on the siting side. The point was, and KEMA team, feel free to correct me here if I'm wrong. But that the developer making the choice to take on those siting, permitting risks because they have got, because automatically the feed-in tariff makes the entire proposition lower risk and allows them a bit more headroom to absorb increased costs of permitting, siting, other things as the project moves forward. Is that accurate?

ADVISOR TUTT: Wouldn't the long-term contract also do that for them or not?

MR. RICKERSON: I think depending on how the long-term contract is set up. If it's a standard offer contract versus a contract where there is risk involved with the bidding and there are incentives to potentially speculatively bid the price in a certain way. It might not be. Let's see them side by side and how it would pencil out with feed-in tariffs. You would be able to know what you're going to get and there's less risk and less cost, in theory.

ADVISOR TUTT: Thank you.

MR. LEAON: Any other questions from the dais?

CPUC ADVISOR ST. MARIE: Thank you for that very good presentation. When you say on slide number eight that a feed-in tariff might in the ideal reduce risk without increasing ratepayer cost. And I just numbered it on our paper, we don't see the numbers over here. It is: But Feed-In Tariffs Might number one. Yes, you've got it up. Which risk are you talking about there? Is that the ultimate risk to retail ratepayers? Is that risk to the agencies that sell that power, that is the wholesale suppliers?

MR. RICKERSON: I think this is

specifically referring to developer risk.

CPUC ADVISOR ST. MARIE: Developer risk.

MR. RICKERSON: So you are reducing developer risk. I think this generally refers to near-market resources.

CPUC ADVISOR ST. MARIE: Okay.

MR. RICKERSON: I think it's a different proposition when you start talking about emerging resources, where if you are actually going to set a technology-differentiated rate targeting, you know, profitability for that resource it might change.

But in some of the modeling I have seen in some parts of the country, if you've got a 20 year contract for some of the near-market resources that's at or near market price right now, or even slightly higher with a slight premium, that does have the potential to be a hedge and actually have ratepayer savings over the long term.

I think it also refers to the fact that with the 20 year or however long -- with the certainty from the contractor payment you also get lower cost of capital from that lower risk and so that also, you know. That lower risk premium reduces costs for the ratepayers ultimately as well, as we saw in the New Jersey analysis.

CPUC ADVISOR ST. MARIE: Okay. Primarily this is developer risk, though, that you are talking about?

MR. RICKERSON: Yes.

CPUC ADVISOR ST. MARIE: Okay. I recall many years ago when Britain first began to experiment with the restructuring of its markets that they were interested in what they referred to as an infinite bus. Any consumer could connect to the transmission grid anywhere, any producer could connect to the transmission grid anywhere. They ultimately abandoned that because even there they could not build transmission fast enough to connect to everyone who wished to connect wherever they wished to.

The idea of the German derivation of the feed-in tariff, which I am grateful to you for explicating for us, is that generators could connect wherever they wished. Has that part of the feed-in tariff been successful? That is, are Germans and others able to build transmission lines to wherever it is that generators would wish to connect?

MR. RICKERSON: I think a definitive answer on that is a bit above my head and I have to look elsewhere. But in general I think they have been fairly successful. Keeping in mind that Germany is a country of 80 million and about four percent of our land mass. So it's much denser both in terms of its load center and its populations and also its existing transmission infrastructure. So I think that's, you know.

One thing that gives people pause about a direct transfer of feed-in tariffs over the United States, especially at the federal level, is if you had an open-ended feed-in tariff in some place like North Dakota. It would be a decidedly different environment to operate in than in Germany where we have few people, minimal transmission and a great resource.

CPUC ADVISOR ST. MARIE: You don't have to go to North Dakota to find transmission problems.

(Laughter)

CPUC ADVISOR ST. MARIE: We have them here. I am now on page 15 in the Denmark slide.

MR. RICKERSON: Yes.

CPUC ADVISOR ST. MARIE: In 1992 the

feed-in tariff was set at 85 percent of the current retail rate. I presume that is the then current retail rate. And would that be a floating number? As retail rates changed that number changed?

MR. RICKERSON: Yes. And that's kind of a wrinkle in feed-in tariffs, that generally they have been fixed across time. And in the German example, anyway, there was a float with retail. And it ultimately turned out to be problematic, which is why they switched. And why Denmark tried to switch and failed with its alternative.

CPUC ADVISOR ST. MARIE: All right. Okay, thank you, those are my questions.

MR. RICKERSON: Thanks.

MR. LEAON: Okay, any more questions from the dais before we go to blue cards? Okay.

First let me say that we are going to get our full allotment of time in for the next presentation. We may run a little past 11:45 before we break for lunch. But I think it's important that we take the time to allow for questions and make sure that we get all the time in for the next presentation as well.

Okay, I do have two blue cards. If

there are any other blue cards for Wilson please hand those to staff. The first speaker, Adam Browning with Vote Solar.

MR. BROWNING: Commissioners. Thank you, Wilson, excellent presentation. One question for you. It is currently the policy of the state of California for a 20 percent renewable portfolio standard. Efforts to take it to 33 percent -- There's a ballot initiative this year to go to 50 percent. If you take climate change seriously it's a goal of many of us to get there.

It seems to me at that level of market penetration the utilities have to have a lot of say about the time and place of delivery, given the inherent intermitentness and non-dispatchability of renewables. And it seems to me that a solicitation system deals with that better than a feed-in tariff system. I could be incorrect. Do you have any thoughts on that?

MR. RICKERSON: I mean, it's definitely something to take into consideration, as you all --

VOICE OVER THE SPEAKER: (Indiscernible).

MR. RICKERSON: Hello? Am I the only

one who heard that?

(Laughter)

MR. RICKERSON: I think that's something for the state to consider, obviously as you move forward. As I think Bob will be getting into later, there are different ways to take time value and send market signals through a feed-in tariff. Similar to how the CPUC has already approached it, say with the time value of money. And that's kind of inherently bundled in there. In some other countries they differentiate also by season, not just by time of day. And it is all in how you want to set it up.

You know, that general definition of a feed-in tariff, long-term investor security, is kind of the shell. You know, some kind of long-term standing offer, standing offer price. How do you fill in all the details of that shell, I think is what we are going to be spending the rest of the day on if there are strategies for doing that.

MR. BROWNING: Thank you, Wilson.

MR. RICKERSON: Sure.

MR. LEAON: All right, thank you. The next speaker, Carl Zichella, Sierra Club.

MR. ZICHELLA: Good morning, Wilson,

great job. I have a question. Some feed-in tariffs are designed to have a declining tariff over time.

MR. RICKERSON: Yes.

MR. ZICHELLA: And I wonder if you could talk a little bit about that.

MR. RICKERSON: Sure.

MR. ZICHELLA: Because it allows for cost recovery of front loads on some of the security for investors early, but then it sort of reduces the bite on ratepayers later.

MR. RICKERSON: Just to be -- And we will get to this later. Just to make it a quick distinction. In certain feed-in tariffs, like the German feed-in tariff, there's a declining schedule. What that means is if you lock in in 2007 you get a higher price for 20 years than if you locked in in 2008. So there's a decline in the 20 year price you get. That's one type of decline.

A second type of decline is in things like the German wind feed-in tariff where you get a high price for the first, let's say, five years, then it drops down to a secondary level. Both of those levels are fixed over time though so you know what they are ahead of time. And that's I think what you are referring to with front-loading and dropping. Again, design, design, design.

MR. LEAON: Okay, I think we have time for a couple more questions. Let me ask our web host. Do we have any?

MR. FLESHMAN: Yes, we do have one, Sean Simon.

MR. LEAON: Okay, let's take a question through WebEx, Sean Simon. Sean.

MR. SIMON: Hello, Sean Simon, California Public Utilities Commission. Actually I was hoping to just type this in. But my request is if you might ask the speakers who have comments or questions that they identify themselves for us on the WebEx. And I will leave with that, thanks.

MR. LEAON: Okay. I think that probably relates to the questions from the dais, yes. Thank you.

Okay, I have one more blue card, Craig Lewis, Green Volts.

MR. LEWIS: Yes, hi. Green Volts is maybe coming from a somewhat unique position in that we actually have successfully navigated the RPS/RFO process and we have a two megawatt contract with PG&E. It's a PPA for a concentrating photovoltaic project. So we have actually successfully navigated the RPS program.

It's a CPUC-approved deal. One of only three solar deals that have navigated that process thus far. And it's a small deal so we also have suffered the consequences of having a lot of high overhead of transactional costs associated with the RFO process and having to leverage that over a relatively small deal at two megawatts.

So I was a little confused as to whether this conversation is going at 20 megawatts and below. It seems like all of the serious feed-in tariff initiatives that are happening in the United States are really focused at 20 megawatts and below so I hope that that is part of the conversation here today.

And I had a couple of questions for Wilson. I thought that was an excellent presentation. It brought a lot of really good information to the conversation here in California.

And the first thing I wanted to, I guess just clarify, is that Commissioner Byron had asked a very specific question about a standard offer contract versus a RFO process. And it seems to me that a standard offer contract is fundamental to a feed-in tariff program. So at least from Green Volts standpoint, a standard offer contract has to be part of a feed-in tariff program. That eliminates hundreds of thousands of dollars of transaction costs that are associated with the RFO process, whether it's a two megawatt deal, a 20 megawatt deal or a 500 megawatt deal.

Also this is more of a specific question. It seems to me that there's a couple of different methodologies that have been investigated in California for pricing in the feed-in tariff program. Obviously pricing is also fundamental to a feed-in tariff so we've got to get that right.

It seems to me that there has been a -- MPR has been kind of the standard pricing mechanism for feed-in tariffs here in California thus far but the SCE biomass program as well as the AB 1969 base feed-in tariff is priced at MPR.

Wondering if you considered, Wilson, the mechanism of pricing at MPR plus a locational benefits mechanism. So in other words there's higher value for energy that is generated close to load as opposed to further away from load. Wondering if you've investigated that.

Also the national feed-in tariff bill that you mentioned that was introduced on Thursday by Congressman Inslee. That basically takes a -- it sets the pricing, I think it's at the 80th percentile in terms of the resource strength by region. So it seemed like a very interesting way, a very effective way to set pricing.

It's a cost-plus. And the way it develops the cost is it takes the 80th percentile of where that resource is. So the solar resource, you would take where the solar resource quality is at basically the 80th percentile in the US, develops the cost of that technology at that resource quality level, and then adds a ten percent cost adder or profit onto that cost.

So wondering how much thought you have given to those two pricing mechanisms and if you'd comment on that.

MR. RICKERSON: I'm sorry, I seem like I'm dodging all these things. It's not because I'm trying to be evasive but because a lot of this is what we are going to be getting into during the next presentation. So for example with the RFO, a part of a standard offer or not. Again I think that in general across the board most feed-in tariffs do not have some kind of competitive process.

Could there be where you have a competitive process that sets a price that then becomes a standard offer? Sure. And that's something that we're going to talk about. It's something that has been suggested both in the literature and also at the times for California.

In terms of pricing. I think I'd actually -- Since this is supposed to be an introductory presentation I think I'll punt to the next round of talks if that's okay.

MR. LEAON: And briefly. Again this is Mike Leaon. The focus of our process with the Energy Commission is for projects over 20 megawatts in this process.

I think at this point we need to cut off questions and proceed to our next presentation. KEMA staff will be available to answer your questions. And again I encourage you to submit written comments to support any testimony that you may have given today. Or if you weren't able to get your question answered follow up with written comments.

With that I would like to introduce Bob Grace, our next presenter. Bob is president of Sustainable Energy Advantage, a consulting and advisory firm specializing in technical and policy analysis of renewable energy markets. In this role he has provided analysis, strategy, implementation and support to over 60 public, private and nonprofit sector clients, developing renewable electricity markets and business opportunities.

Bob holds an MS in energy and resources from the University of California, Berkeley and a BS in energy studies from Brown University. Bob's presentation will examine Design and Implementation Issues and Options for using feed-in tariffs in California. Thank you. Bob.

MR. GRACE: Thank you, Mike. As Wilson has shown us there is an increasing amount of activity and interest and buzz around feed-in tariffs. I personally come at this as an analyst who has worked in the industry for awhile on a range of tools to advance the role of renewables, including the development of many of the state RPSs in the country.

And I approach this as an agnostic. Not as an advocate for feed-in tariffs but really as an analyst curious about what role, if any, feed-in tariffs might be able to play in meeting the policy objectives in place in California and elsewhere.

The purpose of the Issues Options paper out of this presentation is to give us all an operational understanding of this tool and its features. The different ways that you can develop a feed-in tariff. Think of it as a users manual, if you will, to arm all of us for productive discussion of what such a tool might be able to do and then help us collectively decide whether there are jobs that need to be done in California that this might be a tool to help.

So in putting this report and the presentation together we have looked to feed-in tariffs as a tool, much like RPS is a tool. Not asking what's wrong with the RPS or what the RPS isn't doing, but rather what are we trying to accomplish in California. That having gained that common understanding, do we have objectives where this tool can help, and if so, how.

Now Mike mentioned earlier on, and

you'll see a number of slides in this presentation referring to a survey, an online survey. We have created something of a novel approach. I don't think it's been used here in California before. Where we have -- in order to facilitate some of the public stakeholder input we have developed an online survey. And you will see here in this presentation a number of slides as a survey question.

Rather than reading them -- I don't plan to get into and discuss them in-depth here today. But this is offered in an effort to get more detailed and targeted stakeholder input on the various objectives as well as the design issues and options that could be accomplished in this workshop-type format.

There are a lot of questions and we certainly don't have the length of time to get into that kind of detail. And also to help us organize our input and be able to take it further in a more usable manner into development of the next work product, the paper with recommendations.

In addition we will be still taking, the Commission will be taking written comment. This online tool hopefully will serve as a mechanism for those who might not want to submit detailed, written comments but would welcome the chance to use such a tool in a way that saves them time and effort. You don't have to go wordsmithing detailed comments but still be able to help the Commission with feedback on the direct and more detailed implementation issues. As well as for those who do plan to provide detailed written comments at the higher level, some of the questions that we will be talking about this afternoon, but also wish to contribute some input on the more detailed design issues.

A link to the survey will be posted on the Commission website by no later than the close of business on the 7th of July and possibly as early as the close of business on the 3rd of July. The deadline for completing that survey will be the same as for the written comments, July 11th.

So we are introducing the questions here. The questions track very closely along with the structure of the Issues Options paper as well as the PowerPoint, as you will see laid out in the presentation. We were hoping that those stakeholders who wish to submit responses to the online survey could use this hard copy of this presentation to prepare yourselves to take the online survey in a time-efficient fashion.

In the previous PowerPoint and this, Wilson and I both put a lot of effort into both of these. There may be some questions that were asked earlier that if you don't find them answered adequately or want to probe further than I may be able to help elaborate on -- and certainly in response to questions and answers on this. There are a number of topics that Wilson would be more prepared to answer on. So when we get to the question and answer state here I am going to be asking Wilson to come up and join me.

So now on to the presentation. The most important thing in any policy design is what are we trying to accomplish. And as we talk through the various options, the issues and options available to us, we are going to need to keep touching back on what were our objectives. Because the design will need to follow the objectives.

And intimately related will be measures of success. what are the potential goals of a feed-in tariff? Quantity. Do you want to maximize generation? Are you going to measure that in megawatts or percent of retail sales? Or are you going to want to be looking at developing certain quantities of certain types of renewables over a specified time period?

From the cost perspective. Will you be looking to minimize rate impact on retail customers or minimize transmission costs or minimize contract regulatory oversight costs. A lot of different ways you can look at this.

Diversity. Are you looking to do what the RPS does right now and get the most renewables, the biggest bang for the buck? Or are you going to be looking for promoting certain generation technologies, smaller projects, certain business structures, projects in certain geographic areas.

There are a number of other objectives here. But I think it is going to be critical to our collective effort to get some kind of an articulation of the objectives and the associated measures of success. And prioritization of those as well because ultimately a lot of these objectives will conflict.

This is an example of the articulation of the survey questions. I won't be going into them here. But this is what you will see in the online survey in the survey question boxes.

And an opportunity for stakeholders to contribute their thoughts in this case on what the appropriate objectives that a feed-in tariff might be targeted to in California.

Appropriate measures of success on what the appropriate objectives that a feed-in tariff might be targeted to in California. Appropriate measure of success and prioritization.

Now the design issues. There are a lot of different choices to make in coming up with feed-in tariffs. A wide range of those approaches have been taken in feed-in tariffs implemented today. There are lots of approaches that have never been used but are certainly options available in California or combinations of options available to California that maybe hadn't been used together before.

Here we have the list as we have organized them of the different types of design issues. Generator and technology eligibility is one area.

The approach to setting the price.

The structure of the tariff.

The contract duration.

How that price might be adjusted over time.

How it might be differentiated between different technology types or locations or resource quality.

Defining actually what is being sold or purchased under the tariff.

How would the cost be distributed or allocated amongst utilities and ratepayers in the state.

Integration of what's purchased into the power supply of utilities or others if it is not the utilities doing the purchasing.

Issues of access. Which are largely already addressed. In comparison to Europe where the feed-in tariff was part of determining the access to the grid.

Credit and performance assurance. Which is a critical issue in much of the renewable energy policy and would work differently under a feed-in tariff.

Whether we would wish to put in place quantity and cost limits.

And finally, how a feed-in tariff might

interact with other policies of the RPS first and foremost but also AB 32 and the renewable energy transmission initiative, to name two.

So I will be going through each of these in turn and laying out a little description of the issue and the options available. This tracks the structure of the Issues Options paper.

So starting with generator eligibility there are a number of different flavors here.

First, talking about resource type. Which technologies should specifically be targeted. There are a number of different options.

You could set a feed-in tariff that would be applicable to all RPS-eligible renewables and this is similar to what is done in most European countries.

Or you could focus on a subset of eligible resources, mature versus emerging technologies.

In some places the focus has been on targeting certain ownership models so it could be focused on community-owned resources. Or as we already have in place here in California, focusing on wastewater and water treatment facilities.

The pros and cons here of these options depend on other design considerations, and most importantly, on the policy objectives. You really can't answer this without having defined what you are trying to accomplish. As well as the tariff's interaction with other policies.

So again, we will have survey questions that will be available online to seek input on each of those.

The next category here is vintage. Are you focusing the feed-in tariff on new generation or on maintaining existing generation. A similar issue that has been raised in most RPS proceedings.

So one approach you could use is using the current RPS definitions, effectively excluding existing resources.

You could focus on new generators only. This is the typical European approach.

You could focus on defining the tariff as available over a qualification life. So effectively there would be a fixed contract duration that would be adjusted by the years in operation. So if you had a project that was online already for five years and a 20 year contract it would be eligible for 15 years of payments. A new generator would be eligible for 20 years.

Or you could set joint generators online after a certain date.

What are the pros and cons here? Obviously the current RPS definition builds off of existing administrative infrastructure and there's a lot of reason why you might want to go down that path.

Limiting to new projects can prevent overpayment for existing projects. That of course depends on the incentive structure but it would tend to maximize impact of the ratepayer expenditures.

And again the survey questions, which I won't delve into now.

Generator location. Now we have the flexibility of designing a feed-in tariff that could effect -- Let me backtrack here. This really goes to which tariff a generator could take advantage of. So the options available here are a generator could only take advantage of the tariff of the utility to whom it interconnects.

Or alternatively, if you had some

utilities that didn't have feed-in tariffs, we'll take POUs as an example, could a generator within California take the tariff of another utility. Somebody who it didn't interconnect to.

If so would it require energy delivery to that utility? So if we had a generator here in Sacramento could it decide to take advantage of SCE's feed-in tariff, for example. Would it require delivery? Could they only take advantage of the nearest option?

Another option here is can any California feed-in tariff be accessed by any generator anywhere? Could it be with delivery or access via RECs?

The pros and cons here range pretty widely. In general all the feed-in tariffs to date have been of the first category, only from the utility to whom you interconnect. So this is consistent with all of the other feed-in tariffs that we are aware of that are known to work.

At the same time this could restrict supply. It leaves out some areas if some utilities don't offer tariffs. And it leaves out generation outside of California, which may more may not be desirable.

The next category is a generator could access any feed-in tariff if you are a generator within California. So this would expand access in supply. Especially when there are utilities that might not offer a tariff.

A con here however, is if the tariff rates differ. Then you are going to have generators that will chase the best available tariff and that could create some issues.

The final category here is any California feed-in tariff would be available to any generator with energy delivery. So this again would expand supply. And again, if utilities have differentiated rates this is going to have generators chasing the best-available rate.

But here you have an opportunity for utilities outside of California to contract and access so that would expand supply. Potentially create some savings to ratepayers.

On the other hand it is going to minimize the local benefits of generation in California. Similar issues to those that have been wrestled with in the RPS context. A similar set of design choices.

So again the survey questions will

attempt to probe some feedback on that.

So another option here is interconnecting utility requirements. This gets into the question of, should all utilities be required to offer tariffs or just a subset. Would POUs and IOUs establish tariffs or just IOUs.

In terms of the pros and cons. If the statewide requirement provides access for all eligible generators, doesn't leave anybody out.

On the other hand, imposing feed-in tariffs requirements on some of the smaller POUs may tend to be burdensome. In the big picture I think feed-in tariffs are unambiguously lower transaction costs than the RPS. But when you are dealing with smaller utilities that may not be the case.

So another option is project size. Would you set size limits, either maximums or minimums, in terms of capacity or energy. So one option is no size limit. Any generator can take a tariff.

Another, capacity-based, project size caps.

Or capacity-based size floors.

Again, for a minimum or maximum instead

of using a capacity-based structure in some cases tariffs would be designed with energy-based project size limits, which can differentiate based on resource intensity or capacity factor.

Now the no limit approach makes small projects competitive and could potentially accelerate progress.

On the other hand there is the potential that large projects might dominate, especially if the overall quantity is kept. You could have one or two big projects come in and effectively fully subscribe the tariff.

Introducing size caps is one approach to mitigating that risk. Now depending on how set that there is the possibility that you could specifically use this to target systems of sizes that might fall between the cracks, whether it's below 20 megawatts or perhaps there is a level between 20 megawatts and something higher where some projects are not able to compete effectively in an RPS context but might come online in response to a feed-in tariff of a similar price target.

You've got the ability to encourage distributed generation and you have the potential to control market growth and policy costs by limiting the participation.

Again if you have a project size cap you have got the possibility that large projects may attempt to work around that cap by fragmenting into multiple smaller projects so it may not be effective.

In terms of size floors. You might decide that this tariff will be set to encourage large-scale development and as such it could do that. In doing so then you might not achieve the small scale distributed energy policy objective. So again this comes to, what are you trying to accomplish.

In terms of the option of limited resource intensity or capacity factor. You could use this as has been done to target project development in areas with marginal renewable energy resources. Wilson touched earlier on the German example of distributing capacity into places with weaker resources and you can use this approach.

Again, as Wilson pointed out earlier, this creates the possibility of providing support for projects that don't generate a lot of energy.

If that is not your policy objective then you are not going to want to go down that path.

So that's the realm of potential eligibility design choices. Now I am going to start talking about setting the price. There are a number of different approaches to setting the price. Wilson has touched on them by way of example but now I am going to put some labels on them.

One approach is what we'll call value-based payment. So generators get to pay based on the value of what it contributes to its system. Or the commodities. The energy capacity and so forth.

So the options here are, you have a base payment based on the value of the energy delivered.

You could modify that so that you would crete time-of delivery adders.

Or adders to recognize environmental externalities or grid size benefits. One of our questioners in the last round here had been getting at this. You could create an adder for desirable locations.

You could choose a wholesale versus a

retail price reference.

So the pros and cons of the value-based approach. Basically the pros: This is a very technology-neutral approach. It is very similar to what has been done in California today in terms of using the market-price referent. It does give you the ability to crete rapid market growth since positive market signals to generators that can dispatch on peak. You've got time-of delivery differentiation.

But the cons here are that this approach doesn't address the value of diversity or technology diversity in particular. While you could tweak it, as many RPSs have been tweaked to create technology tiers you could also tweak a value-based feed-in tariff to achieve other objectives through the selective use of adders.

That may be a fairly indirect way to get at what there's a tool to do more directly, which is generation cost base payments. And many of the examples that Wilson gave fall into this category where the price is set to ensure each technology sufficient profitability.

This is basically an administratively determined estimate of capital operating finance costs, tax incentives. What is it going to take to attract sufficient investment and get a generator online.

Options include setting the profit level. So you would administratively determine a return on investment. And there are a number of different ways to go about doing that.

When you are designing that cost payment there are two different philosophies you could take. A conservative philosophy where you would be targeting the most competitive developers or scale or resource quality within each technology type. So this is going to be more similar to the RPS outcome where the best, most cost-effective resources are going to be the ones that can play and that will be able to come online and respond successfully to a feed-in tariff.

On the other end of the spectrum you could take an aggressive point. So you could set prices high enough to allow a broad range of systems of different sizes, types and resources.

In reference to one of our questioners had brought up the 80th percentile approach in the federal bill. Think of it this way. So a 90th percentile might be a conservative approach or you might set a price that would attract based on the 30th percentile. So a much broader range. It would be a higher price so some project would tend to make a higher return but a wider rage of projects would be able to come online.

And tariff differentiation touches on similar issues and we'll be talking about them more later -- in a little while.

So pros and cons here. The European Union has concluded that it is able to successfully set prices more accurately and effectively than quantity targets. That's certainly one of the big issues here.

It simultaneously moves each technology down its experience curve more rapidly so you may be able to make it a more cost-effective -- or this may be more cost-effective in the long term than exhausting the cheapest technologies first.

Aggressive targets can entice less mature, more costly technologies and effectively accelerate an industry more quickly. Or end up having less efficient sites or scales.

Now one question that has been not well-tested in Europe is competitive benchmarks. And this gets to how do you administratively select a price on a cost-based context. Coming up with a competitive benchmark would allow you to replace an administrative determination of cost and profit. And the reason you might think about this is in part because of the physical situation we have here in the US relative to Europe.

In Europe you've got dense population, not a lot of locations where you could build large projects in a fairly saturated market. So the risk of setting a price and then having a 2,000 megawatt wind project go and take it and having set that price too high has really never been a material risk in Europe. But I think it is very much a risk here in the US. So one way to get at that is to determine a competitive benchmark.

What are your design options? Well, you could do this in a number of different ways. You could focus this on all resources or just on differentiated types of projects.

The mechanism and frequency by which you might go about determining benchmark. Well you could set all prices determined on a periodic option or solicitation. But at that point it doesn't look very much different than an RPS.

Alternatively you could use a recent

representative benchmark that might have an adjustment factor. So here is an example. You could say, the last RPS solicitation, we'll take all comers at 95 percent of that price.

You basically have a mechanism where you know that the price that you are offering is within the realm of what you would have gotten in a competitive context. And so you could do that. You have the opportunity, potentially, to weave in, in a periodic solicitation, say for solar. And then use the result of that to subsequently set a feed-in tariff price.

The advantage of doing this is you are mitigating the risk of setting the tariff too high. The con is it could be administratively cumbersome. This is an area where I don't believe this has been done before, although I think Wilson came across recently the first potential example of using a similar approach.

So the next design choice is tariff structure. The number of different structural options. The variations in terms of the present risk profile, the degrees of revenue certainty, and the interaction with electricity markets.

Obviously revenue certainty is one of the key reasons that you would consider establishing a feed-in tariff.

So one option is just setting a fixed price over a multi-year contract.

Another is a stepped fixed price, as Wilson graphically demonstrated. Where the price would come down over the latter years of a contract.

You could have a fixed premium that floats on top of the market price. Again Wilson has pointed out that that has had some issues in terms of not providing as much revenue certainty.

You could have a hybrid approach in which generators can disaggregate the selling of certain commodities or attributes under a feed-in tariff and others sold to the marketplace.

You could have a contract for differences, or what's known as a fixed-for-floating swap. This is basically a financial settlement rather that the purchase of electricity where you might set a price. It's a ten cents a kilowatt hour. And to the extent that market prices fluctuate above or below that there would be payments either to or from the generator so that at the end of the day they are left with their strike price. That revenue certainty, without necessarily having to have a power contract that the utilities or others would have to manage.

What are some of the pros and cons of these approaches. Well the fixed price provides the greatest revenue certainty. Some of the detractors have noted there that having that fixed price creates no incentive to operate at system peak times.

The stepped fixed priced. Again revenue certainty. It allows and really facilitates a transition off of over-market support. And you can use it again to differentiate resources.

The same problem with the fixed price. No incentive to operate at system peak. And again it would be administratively more complex to set.

The fixed premium allows generators to receive electricity market price signals to operate when their output is most desired. At the same time, if electricity market prices rise, it's more costly for customers and more profitable for the generators. So effectively that loses the opportunity to use that feed-in tariff as a way of hedging retail customer costs. And that was one of the issues that Wilson brought up with, Denmark was it?

MR. RICKERSON: Spain.

MR. GRACE: Spain, thank you. The hybrid approach. Again, if some of the generation products are purchased under a feed-in tariff and others are sold at market. Well that shares the policy risk between developers and ratepayers.

On the other hand investors are still partially exposed to volatility, for instance, the REC market. It depends on what product we're selling here. But in still exposing those investors to that volatility you lose some of the benefit of reducing risk and therefore the cost of capital to those generators.

The contract-for-difference approach does allow you to have the revenue certainty for generators. The same problem as with the cons. No incentive to operate at a system peak. One advantage that I didn't put up here is if you take this path you don't have to have the utilities manage an unknown influx of generation into their power supply. I'll be coming back and talking about that a little bit more later.

Okay, so you are going to offer a feed-in tariff and you've figured out how to set the price. How long are you going to offer that tariff for? Setting the price and the length of the contract are closely linked. Certainly for capital-intensive technologies the shorter you make your contract the higher you are going to need to make the initial payment in order to make it attractive for investors to invest.

So you have choices here. You could have a short-term tariff, maybe in the three to seven year time frame. In this case there would be potentially less risk for investors if they can pull out their investment quickly. I think that is really a very solar perspective or solar-oriented perspective that some stakeholders in New Jersey have put forth. Really a lower ratepayer impact for high-cost technologies has been argued.

The con here is that you would have a much larger up-front rate shock. Investors don't have the incentive to maintain the technology over time. And you lose the potential for near-term technologies to serve as a hedge to market prices over a long-term.

A medium duration contract lowers the

risk due to the long-term contract. It allows for amortization of capital costs over a longer period. It balances out the risks between the short- and long-term contracts. I'll talk about the long in a moment. And would result in a more moderate rate impact than the short-term option.

A longer term contract. And most feed-in tariffs would fall into this category, the 15 to 20 years. It creates an opportunity for near-market technologies to serve as a hedge. It does create a potential risk for technologies with fuel costs, particularly biomass. It can be very difficult if not impossible for biomass plants to lock in their costs over any period of time. So you may decide that for biomass it would be more appropriate to have a shorter term feed-in tariff and for more capital-intensive generators to have a long-term.

Another option is to have an optional contract term that offers developers a range of contract lengths to choose from. Well this could provide developers with the flexibility to determine the appropriate contract length for their needs but it would create additional administrative uncertainties with regard to the total life of the program, as well as additional complexities for managing those contracts within power supply.

An indefinite term is another option. It provides developers with a guaranteed revenue stream for the life of the project. Here I think it becomes harder to calculate what the appropriate price is in that context. And as well ratepayer costs may exceed the duration required to achieve the objectives. So that might not be in ratepayers' best interest.

Now what about adjusting prices over time. Another issue that was brought up and Wilson gave several examples of how this has been done.

The options available to consider here. This really provides flexibility to periodically adjust tariff prices towards the right level, however that may be defined.

So you could have a feed-in tariff that has no adjustments. The tariff was set and left at a specified level indefinitely. It certainly creates a great deal of certainty but it does not allow you to be price responsive.

And just for clarification here, I am

talking about the price available to a generator that comes online at any particular point in time. So a 2009 generator would get this price, a 2010 generator may get a different price. this is how we determine the price available to generators that come online in different years, as opposed to adjusting the price available to that specific generator.

So you could have a price that's fixed with an inflation adjustment. So the tariff level would periodically adjust for those new and operating plants.

You could have tariff digression. We'll talk about this in length shortly. But basically the level of incentive payment available to new plants would reduce over time. That takes into account the potential for generation technologies to benefit from falling prices that come with scale economies and technology advancement.

You could have an indexed that changes with the measure of value. Wilson had pointed out tariffs that were linked to retail rates. Or here in the MPR context they are linked to the future outlook on wholesale rates in any particular point in time. So this really fits the cost-based context. And in this case you would reset the price based on your then-current outlook on future prices.

So pros and cons of these different approaches. The no adjustment is a stable framework, very easy to implement. But it fails to account for changes or to push cost reductions. And really a feed-in tariff can and perhaps should be used to push cost reductions.

Inflation adjustment. Well it provides for increases in certain operating costs but it really fails to account for other types of changes or, again, to push cost reductions.

Tariff digression has been a very commonly used approach and it creates a lot of advantages. It ensures that the incentive changes with new conditions to remain at the right level to be successful, to have generation come online in response to it.

It provides incentives for technology improvement and for investment in, expansion of manufacturing capabilities and capturing scale of economies and encourages cost reductions. So that's a major reason why tariff digression is used widely. And it minimizes the cost of overcompensation over the long term.

However, it is far more administratively complex and potentially costly from that perspective. And again your chosen project tariff digression rates may not match the actual changes in costs over time.

Finally the choice of indexing to the change in the measure of value. So this allows you to keep in line with the current value of the long-term contracts so it is very much like California's MPR approach today with the RPS.

Again, as we all know, this is administratively complex and potentially costly. It could diverge with the costs necessary for generators to earn adequate returns. So again this works with the cost-based approach and doesn't really fit very well with the value-based approach.

Now if you do have an approach in which you allow the price to change you have some different choices on when you would adjust that price. You could have periodic revisions so you would have it pre-scheduled. Every two years you would kick into a new price. There might be a five percent decline every two years, for example.

You might have capacity dependent revisions. Here you would say, quantity blocks. Once you've gotten your first 200 megawatts of solar you are going to kick down to a lower price. In that situation if you have -- You're not locking it, your digression into a projection of when prices will come down. And when prices do come down such that at a higher price the market has been very responsive, you have an ability then to take advantage of that and click on down to a lower price. At that point the fact that the first block has been fully exhausted is a pretty good signal that a lower price is probably viable.

Or you could set up just a process for periodic review. So there's no scheduled decline but there could be a regulatory review every two, three, four years to take a look at whether -- How has the tariff been responded to. Do we have an opportunity to digress the rates an set a new schedule. We'll reconsider prices.

Or on the contrary, if we have a tariff where there has been too little response because costs have increased we may decide it's time to raise that. And then that might be, that might have fit the situation we've seen over the last couple of years.

So the advantages of periodic revision is most predictable for generators. It encourages a stable market. In this type of a situation you really can have vendors and manufacturers, everybody all up the value chain know exactly what's coming and make long-term investment decisions to serving this feed-in tariff.

And it is very administratively straightforward. But if the market transformation doesn't occur at the predicted rates then the payment streams may decline at a pace that's detrimental to increasing generation. If you've locked this in ahead of time and you haven't picked the right price then once it starts clicking down you may have all of your response dry up.

The capacity-dependant revisions is really a -- it mitigates that potential risk. So here it is moderately predictable. It encourages generators to come along sooner because the more they wait they may end up taking the lower price. And it encourages a very stable market. So if the steps are small it's very good at making viable prices visible over time. It is more likely to track the transformation of the market and its progress over time.

However, it could create speculative queuing to capture the higher rate. So you've got to -- To the extent that you have a process where the available capacity at a particular price is going to cap you inevitably will have generators that aren't ready rushing to get in line for whatever process you've defined for getting in that line or accessing that higher rate.

And that may create some of the speculative clearing issues that you're having, that we're having today in the RPS context. And again, if the price decline lags behind the market transformation the tariff may rapidly dry up.

So the periodic review is really best able to address the change in circumstances from a regulator perspective. From a investor and developer perspective, however, it is the least predictable.

The next logical question then. If we are going to address the prices in whatever manner we decide when to do it, how much do you adjust the price. Well, you can use what's called experience curves. So you're applying a calculated rate of annual cost decline based on past empirical experience or somebody's projected data on where the technology costs are trending.

Or you could simply set uniform steps. And this tends to go with the capacity block approach where just periodically you step down to a lower price, which is automatically triggered once you hit a certain megawatt level.

Now the experience curves is highly transparent, predictable, and in theory matches achievable cost decreases. It certainly creates incentives to build early and certainly creates incentives for technological improvement.

However, if the digression rate is set for many years the system becomes inflexible, rising prices could alter the trajectory, and you may have a situation where the effectiveness of the tariff dries up.

Perhaps more importantly, it is very administratively difficult to determine the right rate. It really is an exercise in educated guesswork.

The uniform step approach automatically responds to efficiency improvements and economies of scale. Modest steps will increase the likelihood that the tariff is still financially feasible and it's administratively straightforward. So good things to keep in mind if you're going down that path.

Tariff differentiation. Now this is an area where some countries have taken it to an extreme. Wilson, what's the longest list here? What, about 30 or 40 different tiers? Something along those -- And so one might see that that could be administratively complex.

But when a policy is based on generation cost rather than value, how and to what extent should the tariff levels be subdivided? A lot of different ways you can do this. Technology type, wind versus solar. Or fuel type. Biomass, agricultural waste might get a different approach. Or application. Building-integrated PV versus roof-mounted versus solar/thermal and so forth.

Project size. You could set higher levels for smaller projects to recognize scale economies.

Resource quality. You could set higher levels for low-wind to encourage geographic diversity if that were your objective.

Commercial operation date. You could

set different prices to target existing or repowered. This might be a way you have a specific target to encourage repower generation that isn't happening under the RPS context.

Different ownership structure. Perhaps you have an objective that you would like to encourage community ownership and therefore you could set a specific price that worked there.

Transmission access. You could decide to have higher payments for facilities that are near transmission or near load.

And location. You could target generation in a load pocket. Or conversely, discourage a location in a transmission-constrained area.

So obviously the pros and cons of all of these depend completely on your objectives.

Changing gears now. So you set a tariff. We figured out what the pricing is. This is really related to what the pricing is.

What is being purchased under this tariff? You do have different choices. Bundled versus unbundled. Do you look at the renewable, environmental attributes, energy, capacity, ancillary services. I know we don't have all of these markets up and operating and California at this point but it looks like we are going in that direction.

The options you have, the simplest is you are buying everything bundled together. Energy, electricity commodities, energy capacity and ancillary services and all the RECs. End of story.

You could have a commodity-only purchase so you're buying just electric energy or maybe other energy and capacity if applicable and the RECs are being sold off separately into a spot market.

Or you could do the reverse. The tariff is just buying RECs and generators are left to get electricity commodity revenues on their own in the existing markets.

You could have just energy and just RECs. And perhaps unbundled capacity rights and ancillary services could be sold off into the markets.

And finally you could have all the commodities and the RECs but perhaps unbundled other attributes. Tradable emission rights could be sold separately. And that might apply here in

California under very narrow circumstances since the treatment of those environmental attributes is really stapled to part of the REC is largely predetermined.

So what are our advantages and disadvantages of these approaches? Well the bundled approach, it ensures that California ratepayers are going to receive the energy and environmental benefits of what they are paying for.

It may not be consistent with the RPS should the PUC adopt the use of RECs for RPS compliance. A lot of detailed decisions to make there depending on where the regulatory regime goes for the RPS.

Allowing RECs or other attributes to be unbundled. Well this allows generators to access a supplemental revenue stream and a cost-based tariff price therefore could be lower.

This leads to a number of different issues, though. What could be claimed as renewable energy if you are buying just the energy under a tariff well you are really not buying renewables.

If we are actually going elsewhere what

could be counted for RPS compliance? What could be counted towards complying with a feed-in tariff contract if RECs or other attributes were unbundled and sold separately?

So what if you were only to have RECs go under a feed-in tariff? Well then you are compatible with an RPS or renewables market that is characterized by unbundling RECs from energy. And California might go in that direction.

Today California does not allow that but the CPUC is considering it. So if we go down that path this approach becomes a viable one.

And we will look for input on all of those issues.

Let's talk now about cost distribution and allocation. To a large degree this is an obvious situation. Today in the RPS context we have utilities all with a similar target but with very different resource mixes within their resource potential within their territory. So the different utilities are making differential progress towards the goal and the ratepayers are therefore paying differently in reaching towards those goals.

So one question is: Who buys? How are the tariff's costs carried and reflected in the rates? And who has to dispose of the products being purchased?

Given that California is a unique market structure, having gone into a retail competitive market situation and retracted from that but having some residual pockets of different generation service providers. You have IOUs, POUs but you also have ESPs and community choice aggregators.

So one option here for who is doing the buying is the retail generation seller. The other option is the provider of transmission and distribution. In other words, the utilities themselves.

The choice made here dictates how the tariff costs are carried and reflected in rates.

Who has to administer the tariff and the payments.

Who has to dispose of the products being purchased.

Pros and cons. using the retail generation sellers. Well this is consistent with the purchase of electricity to be treated as part of the power supply.

But this could be very cumbersome for small sellers, the ESPs and the CCAs to administer. It could add a great deal of complexity in managing the power supply implications unless all of the supply were sold in the spot markets. It's a option I'll be talking about in a minute.

On the other hand, having the tariff be offered by the T&D utility is certainly simpler to administer. But it requires a distinct management and treatment of the power supply and really it dictates how and where the costs are going to be recovered. Not as part of generation rates but as part of the transmission and distribution component of rates.

So again, who pays? A related issue one needs to think through. Should the costs be allocated across the state regardless of the location of generators? And if so, how can those costs be allocated?

Our options are, to not bother with a statewide reallocation. So as we have today with the RPS, each utility would bear the cost associating with interconnecting generation within its territory.

Alternative you could reallocate the aggregate annual feed-in costs to equalize the costs among all the utilities with feed-in tariffs.

So each utility would bear a share of the cost in proportion to their load. Their ratepayers would be subject to comparable collection and impact.

This could be accomplished in a couple of different ways, either by utility-to-utility transfers of collections, or through perhaps a central agent. The California ISO might be well-positioned to play that role.

Again, another separate issue on who pays is, which ratepayers pay? Would you distribute the cost across all classes or would you exempt some classes from paying here. That is the choice that has been made in some places and it's a choice available in California.

So pros and cons here. Not allocating. Very simple but it may raise costs significantly for utilities in renewable-rich areas that could potentially undermine public support if costs are disproportionately incurred in those renewable-rich areas.

On the other hand, reallocating across the state resolves some of the equity issues, although it adds a level of administrative complexity.

Utility-to-utility in terms of how to reallocate the utility-to-utility transfers. There's some degree of complexity and oversight necessary there.

If you had a third part like the California ISO perform that, operationally it would be very easy. It would be, I think, a fairly straightforward fit or addition to the current functions but it may seem at odds with the ISO's mission and it may require FERC approval.

Finally, the question of exempting certain customer classes. It was obvious if you're in the customer class that gets exempted. But for the perspective of everybody else at the table. I think this results in higher costs borne by customers not exempted and so there is just an equity issue there.

The next nuance is the cost recovery mechanism. Is the cost of the feed-in tariff recovered through generation rates or through a separate charge on distribution rates. Again only relevant because we have the market structure where we have the SPs and CCAs.

If you put it on generation rates the tariff can be part of a general rate case.

You have a limited opportunity potentially if the tariff is part of a broader rate case for the PUC, to focus on specific tariff oversight or evaluate the effectiveness of the contact in the broad rate case versus a more targeted regulatory proceeding.

If you have the charge placed on distribution rates you have greater transparency on how much the tariff costs.

Then you have a number of questions. Who would be the administrator? At what amount should the charge be set? How often do you adjust the charge? How to allocate the funds. How to true-up. Really these are just the administrative details which are necessary in every case. They're just different administrative burdens and details in terms of putting them into play.

Now just a simple question here of who manages the cost collection and distribution. In some places this has been done by different parties. So you could have effectively the state regulators treating this, in effect, like a public goods charge.

You could have the utilities that deal with collecting and distributing. This is what is done in Germany.

You could have a third-party management under contract. This is what is in the federal proposal that we just heard about and other states do this in similar context. Vermont, New Jersey, Delaware have other entities that deal with the collection and distribution and keep it out of the regulatory -- direct regulatory regime.

Integration of whatever is purchased into the power supply of the utilities or others is again a detail. And this one we see very little discussion in the literature. But it's a very real one to those who are managing the power supplies of the utilities.

We have a number of different options. All the generation products in a feed-in tariff could simply be sold in the spot market.

Or all the generation products could be delivered to the utility's system, the interconnecting utility's system, and incorporated into that utility's power supply where we use the generation seller and involve the ESPs and CCAs into their power supply. And then if reallocation is needed one could allocate dollars instead of energy. It's really a financial settlement.

The third option here is all the generation products, energy RECs, capacity, whatever is purchased, could be allocated and delivered to each utility or retail generation service provider in perspective to their respective load.

So if that's the case then there is no reallocation of funds necessary. It certainly makes for a more complex contracting scheme. But the payments to the generators would come from either, would come from each utility directly or through, be allocated through an agent.

So pros and cons of these approaches. All products effectively liquid in to the spot market. The simplest option to implement. No interaction with the power supply procurement and management of any of the utilities. All the power supply managers breath a big sigh of relief they don't have to deal with it.

All generation products incorporated into the interconnecting utility's power supply and any distribution dealt with financially.

Well that's reasonably straightforward, especially if the generation is netted from load. It's very similar to today's context of signing RPS contracts. And allocating costs may have a lower rate impact than allocating generation products because allocating the generation products means somebody has to encourage some additional costs of managing the power supply.

The con here is that to the extent that you have utilities that have a large slug of, or really an indeterminate quantity of power coming into their mix. Again, we don't have RPS contracts. We know exactly what's coming. Here's an advance here. But generators can simply show up with a more limited planning and for notice.

Planning the power supply around that may become more difficult because the remaining load obligations of the utilities become more difficult to quantify and plan for than under the spot market option, certainly.

The final option with all the generation products allocated to and delivered to each retail service or each LSE.

It is certainly consistent with setting

the statewide feed-in tariff target. But this adds quite a bit of complexity for ESPs and CCAs if they are directly involved in terms of interfering with their power supply management and procurement. You certainly would incur higher transaction costs and delivery costs than with the financial reallocation.

And frankly, if these are contracts then you have multiple contracts for every generator rather than a single one. This requires another party, maybe it's the Cal-ISO, to effectively distribute the generation products into different power supply mixes at the ISO.

And if utility delivery is strictly enforced. Well that really works differently from the flexible shaping and firming allowed in the RPS and could result in incurring additional transmission costs. So there are a lot of issues here which might cause us to shy away from taking that path.

So access. As Wilson mentioned earlier, the issue of access was one of the major drivers in Germany and Europe as a whole. Here FERC has, starting with FERC Order 88 we really do have an environment in which access, physical access is guaranteed. It really becomes more of a question of who pays. So the question here really is, who pays for the direct costs of interconnecting feed-in tariff generators to the grid?

Options. The generator pays, the current policy. Or costs are socialized. The generator pays. You are encouraging careful siting of generators to minimize interconnection transmission costs.

Costs being socialized. Well now you are lowering barriers to renewable generation and improving the internal economics of the generators. But you are removing an important price signal for locating plants. So whether you want to depart from the existing policy is a design choice.

There are other costs, however, in addition to just physically interconnecting. There's upstream transmission improvements that may be required to accommodate the generation.

Now here current California ISO policy allocates transmission upgrade costs over 200 kilovolts across all customers. Upgrades under 200 kilovolts, there are more options available. One could choose to allocate the costs to the local transmission owner, that's the current Cal-ISO practice. Or to socialize those costs more broadly.

And similar to the previous slide, one approach, the local transmission owner taking on those lower than 200 kV costs. No action is required and you have got the incentives to locate efficiently.

More broadly socializing those costs, the same as the previous slide. It is consistent with equalizing the cost impact across all ratepayers. Although it does create a dis-incentive to locate projects where they are most needed and to minimize the overall cost to the system.

One other nuance here is that California PUC Rule 21 addresses grid access for distributed generation up to ten megawatts, effectively standardizing the process. And so the question here is, if we had a feed-in tariff for generators above ten megawatts would it make sense to extend that tariff standardization to facilitate the effectiveness and the ease of use of the feed-in tariff? So the choices here are effectively to extend that or to maintain the status quo.

Updating the rule for greater than ten megawatts would certainly make it, it would facilitate easier access for generators and lower their costs, their transaction costs of dealing with interconnection. But whether there are other issues here really requires careful study to ensure that reliability, for example, is not impacted in a negative way.

All right, credit and performance assurance. This is a huge one. If you are a generator having participated in most market structures, credit and performance assurance have been very substantial issues.

There a few different aspects here. There's one topic of this whole PowerPoint where we really moved a topic relative to where it sat in the Issues Options paper, and this one on queuing procedures is one that we have relocated to here. It's treated in Chapter Six earlier on in the Issues Options paper. But it seemed like a better fit here.

So the issue with queuing procedures. So if price declines with quantity or there are quantity caps that apply, then you are going to need to put into place queuing procedures in order to provide generators with price certainty. If you don't bother then you are going to eliminate the primary benefit of having a feed-in tariff.

And that creates the desire to minimize speculative queuing that would tie up access to funds. The type of speculative queuing that we see with speculative bidding with the RPS.

So the different options that you have to deal with that are having an application fee that might be non-refundable. You pay something to get in line. It's at least something of a dis- incentive.

You could have security accompanied with project milestones. So you pay an up-front fee. It would be refundable if the project reaches fruition by a certain milestone date and it is forfeited if a project fails. So that is a dis- incentive to speculative queuing.

Another approach, something we developed and used for the New York RPS and is starting to be used in a number of other places. Where you would have some amount of security required and an initial timetable. And a generator could effectively increase the security by an extension of that timetable. Really this helps separate out the meaningful players from those who are just trying to keep a free option. Effectively placing more security at risk, which you will lose if you don't come online. So these are different ways that you can deal with the queuing issues.

Pros and cons. The application fee is very administratively straightforward. But if the fee is modest it really doesn't do very much to mitigate or discourage speculative queuing.

Security accompanied with a project milestone encourages viable projects if security is sufficiently high. But it is somewhat more administratively burdensome than the application fee. On the other hand it is inflexible. And if a viable project hits a delay outside of its control it could be kicked out of line and that may not be compatible with your objectives.

Finally the security increasing in exchange for time extensions creates a very strong incentive to encourage projects that are real and discourage those that are not viable while acknowledging that there are timing risks in development. I have personally certainly found that this approach seems to fit quite a number of renewables situations.

If you have got a tariff digression, however, this may fail to discourage deep pocket developers from rushing into the queue if a time extension would expose the generator to a lower revenue. so it becomes a little bit less effective if you are going down that design path.

Now other issues associated with credit and performance assurance. You have different general types here, development security. That type of collateral for the period between a contract execution and project operation. For example, the ISOs require development security in the 2008 renewables RFO. It's typically a dollars per kilowatt type of a structure.

And then the other category is operational collateral security. And that is security that is in place once a generator starts operating. And that protects the buyer against the cost of replacement energy or RECs or other products in the event that the seller fails to meet its obligation, fails to properly maintain a generator, or seeks to shake the contract because there is a more lucrative market elsewhere.

Now feed-in tariffs have traditionally not required development or operational security.

It's really been such a different animal that these issues are usually not on the table. And for that reason these issues, which can really increase the cost to a generator. This is one of the areas where a feed-in tariff can lower the cost of generation.

The risk is minimal. It's a very different perspective. In an RPS or any kind of a procurement situation where the buyer has a set target and there might be penalties or implications with not having that generation show up, it is very important to be able to know what you can count on.

In a feed-in tariff, especially if you are reaching for a stretch goal like 33 percent. And right now it doesn't look like you're going to make it, there's not a lot of risk. You want the generation. Because you are not counting on a specific quantity perhaps the risk is minimal compared to a situation where there is more of a reliance on that obligation. And that is why feed-in tariffs have traditionally not had credit and performance assurance.

So pros and cons here. Development security provides protection if the project construction schedule is not met or of the project defaults. And it has a more limited role in addressing queuing issues.

There is little risk -- On the con side. Why wouldn't you want to do it? There's little risk of contract failure if the tariff is above the replacement cost of commodity energy.

The barrier to small generators and developers can be very large and removing this can really enable a broader array of developers to attempt to bring generation to market without limiting viable projects and increasing their costs.

If this is required, one option is to -- you could selectively manage your security to encourage or discourage certain technologies. You could decide to have less security applied to, say solar, where you are not relying on -- Or maybe it's building-integrated solar.

You can decide where your risk reward relies and decide that for some types of generation you are more reliant on the output and therefore having development security is more important. And for others you may want to eliminate a barrier.

Now on the operation collateral or security. Using this type of approach protects the buyers against default or non-performance.

And it protects ratepayers in the event that the tariff is front-loaded. If you have a level payment and a situation where today that looks like an over-market cost but down the line that could be an effective hedge if electricity prices go up. You might want to consider having operational security so that that generator doesn't look to bail out of the contract once it becomes attractive to find a more attractive market.

On the con side here. A buyer, again, is less reliant on delivery of the power supply so the damages are less than in typical contracts. and overly stringent requirements may create a barrier for smaller generators or developers. Or conversely could increase costs.

So we'll ask a number of questions for opinions on that.

Quantity and cost limits. An issue that Wilson brought up in a couple of cases. I think, Commissioner Byron, one of your first questions to Wilson got at these issues.

What are your options? Why would you consider doing this? Well, your options. you could have a quantity cap based on capacity.

Let me step back. Why would you consider having limits? If you were concerned about exceeding your targets you potentially would have limits. If we're looking at 33 percent as a stretch goal there's perhaps not a reason to worry about an overall quantity limit if we think it's going to be a stretch to get there.

And certainly given where we are and where that target is, if you are going to potentially have a risk of overreaching you would see it coming a long time ahead and be able to change the policy well before you actually ended up with more than 33 percent renewables, if that's a real fear.

Now you may want to have quantity caps. Again, for some of the reasons we talked about before. To keep the single generators from dominating. You may want to have floors to focus the support on specific types of generation. So a quantity cap, you could cap the feed-in tariffs at a specific megawatt capacity amount. Typically this would be applied by generation technology or within a differentiated scenario.

You could have a quantity cap based on generation. So you would be looking at the amount of electricity sold. This might be more similar to RPS tiers.

You could have a cost cap that could be based on the rate impact. You could have -- But you would need to define whether queuing -- Are you going to allow queuing to take place?

Let's say, for example, you do impose a cost cap and let's say it's a percent ratepayer impact. If you hit that cost cap what do you do with other generation if you hit your overall quantity targets? Do you simply terminate the whole policy or do you start creating a queuing process and a waiting list until the rate impact cap no longer applies?

Perhaps electricity prices increase and you now are paying less of a premium in the RPS contracts. So a cost cap could apply in certain years and not in others. You have to decide what you want to do before you get there.

Pros and cons. A quantity cap based on megawatt capacity limits uncontrolled growth and costs. But it can create market uncertainty, especially when it depends on queuing protocols. So if you are putting a cap in place and a generator is uncertain to whether they are going to get online before that tariff goes away, that is going to undermine the effectiveness of offering their price certainty.

A quantity cap based on megawatt hours generation similarly limits uncontrolled growth and cost. Again, it can create the same problem, market uncertainty.

Cost caps limits the cost,independent of the capacity and is directly tied to ratepayer impact. But it can be less transparent for market participants and it can create real confusion as to when it would kick in and what would happen if it did kick in.

So we will pose some questions there for feedback.

The final category that we treated in this Issues Options paper had to do with policy interaction. And this perhaps is the one that some of you are most interested in.

How do we integrate the feed-in tariff, if one is to be considered, with the existing RPS framework?

Options include seeing the feed-in tariff as a parallel mechanism to the current RPS solicitation and contracting mechanism. So maybe you don't change a thing in the RPS world but perhaps you would expand the current tariff that's in place right now that applies to smaller projects, simply by removing the 478.4 megawatt cap and having that just a standing price. So while you have the ongoing RPS solicitations you can also have a price for those which is based on MPR or some fraction of MPR that all takers could come under.

In general, it would simply create a different timing opportunity of those generators that might be between cycle. Or there might be some alternatives, some options there to just having the standing price.

Another branch is considering it as a limited alternative to the current contracting mechanism. So you might decide to focus it on only targeting certain types of resources or ownership models. That there might be other policy objectives besides just 33 percent renewables that are in play. The California Solar Initiative, some biomass targets. Would you use this as another parallel tool?

So if you consider it int hat context you could use an MPR-based approach or you could use the generation cost-based approach while leaving the RPS exactly as it is.

The final option is as a replacement for the current mechanism. And that could be either immediately or at some potential time. Or it could be transitioning at some future target. You know, when the RPS has brought us up to X percent, maybe we will get a feed-in tariff beyond that date. That's just the wide range of, the spectrum of potential options and interaction.

What are some of the pros and cons of considering this. Well the parallel to the RPS could help create a diverse renewables mix. It could provide a safety net for projects that are unsuccessful in the RPS bidding process that could come back in and decide, well, we know enough now we could, we could lower our price. We would be willing to come in but we didn't succeed before.

Again, between cycle opportunities sometimes there may be an opportunistic situation created that does not fit the market timing of solicitations. I don't know how much this applies in California but I've seen this all the time in other states where there are generators that simple -- when they are ready to know what their cost is there is no market there for them.

And it could mitigate some of the concerns associated with contract failure.

On the con side, the CPUC has stated that feed-in tariffs should not be open-ended, referencing their Standard Offer 4 history resulting in overwhelming response with too much potential supply. I will pose the question, if we are stretching to reach or not on target to meet 20 percent and we are looking to meet 33 percent, in this context how real a risk is that?

In terms to the approach to limited alternative to the RPS. This would address concerns over open-ended contracting.

It could be used to support targeted policy objectives other than just the 33 percent target.

It could be used to meet, specifically target certain generation technologies or ownership approaches that are unable to compete in the RPS. And as a result could be used to support diversity of generation resource types and locations.

The third branch, RPS replacement. Well, I think we are all aware that the RPS process is a very administratively heavy one. That in theory under some of the feed-in tariff options that we have laid out the feed-in tariff could really be very simple.

So one possible benefit is it could streamline, simplify and accelerate the procurement process in California.

A cost-based contract or near-term market resources could lock in long-term renewable energy prices potentially below the MPR for the most cost-effective renewables. Some have observed that perhaps some of the most cost-effective resources could come online and be willing to come online at a price below the MPR, but because of the current structure are tending to bid at or around the MPR.

So one question is, you know, if there are generators out there that can be profitable for less, is a feed-in tariff the way to target them and lower ratepayer cost? And could that be done? Would be it effective?

A con here. It could certainly raise

the risk of increased ratepayer costs if the tariff level is set too high and generation developed and delivered faster than policy makers can modify the tariff.

And of course the big con is, you know, if it is perceived that RPS is working for what its objectives are then perhaps why touch it.

So the opportunities to weigh in on those questions.

Another policy out there, interaction with AB 32. Well, we haven't probed into this one very much. It's certainly something you keep an eye on. But ultimately the AB 32 implementation details have yet to be decided so it's hard to say very much about it until that happens.

As a general rule, any energy generated from projects receiving a feed-in tariff would be anticipated to be treated in a similar manner to other renewables under AB 32. We haven't been able to say much about it here in Issues and Options but going forward a feed-in tariff is pursued it is something that needs to be considered.

Finally, interaction with competitive renewable energy zones. There is very little, if any, experience in the feed-in tariff world with anything like this.

So we don't have a lot of obvious options to point to other than you could either not differentiate a feed-in tariff according to where generation is located, in or outside of a competitive renewable energy zone, or you could do it. And if you do it well how do you go about determining what's the appropriate price there.

That depends on your objectives. But perhaps it's a way of, some stakeholders have pointed out, the concern of potential exercises of market power within competitive renewable energy zones.

Could you determine appropriate tariff prices for individual technologies based on the RETI calculations that are being made today for each renewable zone? There may be a lot of other options here.

Again, not something that we are prepared to talk about a lot but something that should be considered. One could use the cost estimates that are being developed in Phase 1 of RETI. Those are relatively wide-ranging, reflecting estimates from inside and outside of

California.

How applicable are they in making administrative determinations of the appropriate price levels for each renewable energy one. It could be imprecise, complex and unwieldy. But if there are objectives that suggest that that might be worth considering than perhaps that administrative burden is worth considering.

So at that point I am going to thank you for bearing with me through this long presentation and invite Wilson up to join me to help field any questions that you may have. Thank you.

MR. LEAON: All right, thank you very much, Bob, for that very thorough overview of Issues and Options for Feed-In Tariffs.

Let's take a few minutes for questions now. This afternoon, of course, we will have a session devoted entirely to stakeholder comments and we can really delve into these issues in more depth. But if you have a blue card, questions, please turn those in. And we'll start with questions from the dais.

ASSOCIATE MEMBER BYRON: Mr. Leaon, Mr. Leaon, thank you.

Mr. Grace, very good presentation. I am

not sure that you brought a lot of clarity to it but you certainly got rid of the spectrum on all the issues. Unfortunately I need to go chair a meeting here at noon and so I'll be leaving at this time.

But I think given what we have seen from the scoping plan from the Air Resources Board this last week there is going to be a great deal more push for more renewables, as you can tell, in the electricity sector. So I am certainly keen on making sure we take full advantage of best practices that we have seen in other countries and elsewhere.

And I am counting on you this afternoon to help provide some clarity to that. And at the same time making sure we understand what the Public Utilities Commission's concerns are with regard to the imposition of a feed-in tariff and how that will affect keeping costs down to consumers.

So I apologize, I need to leave at this time. Please carry on.

MR. LEAON: Thank you, Commissioner Byron, we appreciate your participation today.

ASSOCIATE MEMBER BYRON: Thank you.

MR. LEAON: Any other questions from the dais?

CPUC ADVISOR ST. MARIE: Yes, yes I do. I am Steve St. Marie from the California Public Utilities Commission. I appreciated this presentation very much. This is precisely the kind of presentation that keeps my wife from ever asking me, darling, what did you do at the office today and what did you think about. Because it is so complicated and there is so much to it.

But I would like to go back to page 21 of this presentation because I think on that page there is the seed of the entire policy implication that is at the end. On page 21.

MR. RICKERSON: Could you just tell me what the title of that is?

CPUC ADVISOR ST. MARIE: Oh sure. It says, Generation Cost-Based Payments. Generation Cost-Based Payments Pros and Cons.

And the first pro and con is that the EU has concluded that it is able to set prices more accurately and effectively than it is to set quantity targets. That is, that is prescient.

And the reason that I come back to that is, starting with the idea that up to now I thought that we were talking about feed-in tariffs as an aid to reaching RPS goals. But in fact what we are talking about here is which do we understand better and which would we like to be the independent variable that somebody else -- the dependant variable that somebody else controls. Is it Q or P?

The indication of the way that we are talking about feed-in tariffs is that we control P and the outside world controls Q, it comes in from that, okay. I notice that that is precisely the opposite of a cap and trade regime, which we would use for greenhouse gases, to which our renewable portfolio standard is supposed to be an aid.

And in cap and trade, of course, the state controls Q and the market determines what P shall be. Am I the first person to notice this incongruity between the way the Europeans look at feed-in tariffs and the way they look at greenhouses gases? Probably not, okay.

(Laughter)

MR. RICKERSON: No. But I also think they draw a bright line between using a Q-based program or emissions reductions versus a P-based, a price-based, sorry, quantity and trading for reducing versus price-setting for growing a market.

CPUC ADVISOR ST. MARIE: Right.

MR. RICKERSON: And how financing plays in both of those.

CPUC ADVISOR ST. MARIE: So growing the market is not a subsidiary question. It is rather an independent question, separate from how shall we reduce the amount of greenhouse gases. At least in the way that the European regulators and politicians are looking at this.

MR. RICKERSON: I think you'd have to ask me what country.

CPUC ADVISOR ST. MARIE: Okay, well that's fine. I have another question that relates to that. And fortunately you guys have done such a good job of laying out all of these questions that it is hard to find exactly where it is in here. But in Europe do they have the similar patchwork of investor-owned utilities and publicly or governmentaly-owned utilities that are separately regulated through independent parts of law?

MR. RICKERSON: I actually don't know. A lot of European countries have some form of competitive, theoretically introduced retail competition. They also have municipal utilities scattered across the countries as well. I am not sure how they all interact.

CPUC ADVISOR ST. MARIE: Okay. So therefore we are not really sure whether they are responsible to the same types of regulatory organizations. The reason that I am asking this is, one of the difficulties that we have in California is that the investor-owned utilities are subject to the rule of -- I'm sorry -- regulation through the CPUC. Therefore the CPUC is in a position, unfortunately, to impose costs upon them but not upon their neighbors, thereby causing yardstick competition or across the fence competition to be adversely affected.

Okay, sorry. I guess I wasn't really asking a question, was I?

And on page 62. I'll tell you what the title is on that one in just a moment. That is, Integration into Power Supply of Utilities. It's one of the dark slides. Integration into Power supply of Utilities and Others.

MR. GRACE: This one here?

CPUC ADVISOR ST. MARIE: That's exactly

right. The center box, Pros at the top. Simplest option to implement, no interaction with power supply procurement and management. In that, if all generation is sold into spot markets, who takes the residual loss then? Are you saying that taxpayers would buy this stuff at the P set through the tariff, and then when we sell into the spot markets -- And I am presuming it's going to be a loss because otherwise we wouldn't even be talking about this kind of a program. Who takes the loss then?

MR. GRACE: It would be basically all ratepayers.

CPUC ADVISOR ST. MARIE: All ratepayers. So Southern California Edison, PG&E and all of the other companies would have to fund somehow or other the losses that occur through the spot trading?

MR. GRACE: No, let me try to be clear here.

CPUC ADVISOR ST. MARIE: Okay.

MR. GRACE: There's still a contract.

CPUC ADVISOR ST. MARIE: Yes.

MR. GRACE: So you're offering 12 cents a kilowatt hour to so-and-so generator. You are really talking here -- So that payment is clear. You're talking here about what happens with the electricity that's purchased.

CPUC ADVISOR ST. MARIE: Right.

MR. GRACE: Does each utility have to manage it as part of their own power supply optimization? The quantity that they get -- they'd have to purchase elsewhere. The fact that there is this uncertain string means there's greater uncertainty in the quantity that they have to procure elsewhere. So if the utility, having purchased this at 12 cents a kilowatt hour sells it in the spot market and gets --

CPUC ADVISOR ST. MARIE: Six.

MR. GRACE: Six, then the other six are coming from the ratepayers. Ultimately they are still paying 12 cents. The dollars all settle out. It's really no different between these options. It's really a matter of power supply management and operations.

CPUC ADVISOR ST. MARIE: Okay. So the real point of this is not that this is the financial arrangement through which the power is purchased. This is the way that the utility, having purchased the power, should settle its quantity accounts.

MR. GRACE: Yes, that's all I can tell you. Most stakeholders really could care less about this. But those who operate the power supply and make those decisions and interact with the ISO care completely because this completely affects their jobs.

CPUC ADVISOR ST. MARIE: Okay. Well thank you, those are my questions.

MR. LEAON: Okay, any other questions from the dais?

ADVISOR TUTT: Yes, just a few, if I may. This is Tim Tutt at the Energy Commission.

Again I am going to refer to slides and maybe I'll give the title too. Slide 10, Generator Location. You talk about a variety of options for eligibility for generators to be interconnecting to specific utilities.

MR. GRACE: Yes.

ADVISOR TUTT: Did you consider something similar to the federal proposal where there would be a California-wide feed-in tariff or interconnection policy? It wouldn't be specific to each utility.

MR. GRACE: I think that would really

fall into one category or another here. As was pointed out earlier, jurisdiction is an issue. If you have a tariff in all utilities then the question of a generator and a utility without a tariff doesn't apply. So I think that is simply depending on how your defining falls into category or another here.

You still have the question of, are the tariffs -- If the tariffs are not different than there is no issue of generators chasing a higher tariff. If they are available everywhere in California then you don't have a question of whether a generator does not have access to a tariff. This whole slide in the example that you have laid out would devolve to inside and outside of California. If you have a tariff in California are generators in other states eligible to avail themselves of it?

ADVISOR TUTT: My next question is on the slide that Mr. St. Marie mentioned, the Generation Cost-Based Payments. The EU conclusion, 21.

By the way, Steve, I also arrived at that conclusion that there was a question of price versus quantity in what we are discussing here.

But my question is related specifically to the EU results. As I understand those results they were comparing feed-in tariff policies in Europe to really kind of volatile REC market policies in Europe. So I guess what I am questioning is whether or not there was an alternative with long-term contracts associated with an RPS that was a part of these results?

MR. RICKERSON: You're right, it is a very narrow academic question about tradable versus fixed prices and kind of the risk associated with those. I think when you get into asking would an RPS with long-term contracts -- Definitionally that's a little problematic.

As Bob just walked through there, the way we mine for a lot of these design choices, we mine for them from actual policies in Europe and around the rest of the world. So once you get into what a feed-in tariff actually is and how long-term contracting interacts with different quantity targets and cost caps et cetera, we could find an exemption in every single one of those. The short answer.

So yes, they were taken into account. But necessarily with a competitive benchmark.

Laying off that as well.

MR. GRACE: And this actually gets on to during Wilson's talk I think he misinterpreted a signal that I had given him here that he had hit the wrong button and gone back to the previous slide to mean he should hurry up and he skimmed by what I think is one of our most important conclusions, right on your point here.

Certainly where I personally call into question some of the conclusions, some of these universal, sweeping conclusions that the European Union and the feed-in tariffs are universally better than RPS.

If you look at the specifics of those analyses, most of the points were there pointing out why a feed-in tariff is better than an RPS were not criticisms of an RPS generally but of a specific design issue or flaw. Depending on which RPS you were comparing to you might come up with very different answers. So is a feed-in tariff better than an RPS or just that RPS? And that affects our outlook here and I think a little more neutral approach to these two technologies -- these two policy approaches.

ADVISOR TUTT: Okay. My next question

is further along on the slide titled, When to Adjust Price? It's slide 37, I think. You found it, it was just the last one. That one, yes.

There was talk there about periodic revisions and periodic review. And I guess my understanding of sort of the German experience currently with solar feed-in tariffs is that they had a schedule of periodic revisions. They have also gone through periodic review. And in fact recently made significant changes in their schedule of periodic revisions. Is that --

MR. RICKERSON: That's accurate. In fact, the Germans have both. They have periodic revisions based on time but they also have, every two years, a review where they see how the market is going, which is where we got this latest increase in the PV digression rates.

Periodic review is we see -- Most of the Michigan model states that have proposed legislation here in the US haven't had a digression rate but they have had a two year periodic review without a fixed revision schedule.

ADVISOR TUTT: Finally, near the end on Integration of Feed-In Tariffs with Existing RPS. I think it's slide 81.

MR. GRACE: This one?

ADVISOR TUTT: One back I think. Yes. I guess the question I have is, is the option of having a feed-in tariff parallel to the current RPS solicitation contracting mechanism? I think right now we have a current policy of a limited alternative to the RPS with our smaller size feed-in tariffs.

In this parallel structure have you looked at what would happen to some of the legal requirements of our RPS such as the current above-market funds policy with a feed-in tariff structure? And I think there's a clause in the law that limits renewable procurement or the requirement for renewable procurement to 20 percent at present.

MR. GRACE: The short answer is no, we really laid these out as generic alternatives.

ADVISOR TUTT: Okay.

MR. GRACE: Looking at the specifics is really the next phase of the effort.

ADVISOR TUTT: Thank you.

MR. LEAON: Okay, thank you, Tim. Any other questions? Okay.

Let's proceed to our blue cards. And

let's see. The first speaker is Gary Matteson, Mattesons and Associates.

MR. MATTESON: A question. This is a comment I have. Should I defer to a later period or should I go ahead at this time?

MR. LEAON: Well, why don't you go ahead.

MR. MATTESON: Okay. Your report identifies which resources are eligible to receive the feed-in tariff rates. This is page 13 and slides 6 through 15. Resource Type then each Location, Interconnecting Utility and Project Size.

I would like to recommend an additional criterion for eligibility, sustainable practices that are based on environment and developmental principles.

I have recently been working with the board of directors of the California Biomass Collaborative on certification incentives and market development for a sustainable biomass industry. For that group the principles are greenhouse gas balance, carbon sinks, existing food supplies, biodiversity, land availability, water availability, air quality, local economic development, social well-being of employees and transparency to the public.

Many of these concepts are transferrable to the entire revenue -- excuse me -- the entire renewable energy venue.

Chapter 8, page 45, or slide 46 of your report states, California policy makers should decide up front what is and what is not included in the tariff, in the feed-in tariff.

It is my recommendation that the Environmental and Development Act should be included in the feed-in tariff.

The Bureau of Land Management seems to have this concept in line as they are planning an extensive environmental study on large solar plants being placed on public land. Another example is New Hampshire's REC planning where they have placed a moratorium on combustion of construction and demolition waste to fuel energy projects.

Kramer, et al. has proposed a set of principles for testing framework of sustainable biomass. I have expanded on this set of principles in my recent paper. Others have proposed principles including 25 By 25 by American

Energy Future and the Round Table on Sustainable Biofuels.

Slide 74, Chapter 12, of your report states, different forms of credit and security requirements can be imposed to protect against the risk of a new project going forward or non-performing. I would like to have you focus on certification and compliance in the design of the credit and security requirements.

I have also developed measurement certification systems with compliant features for the biomass industry. The US Forest Service has also developed a similar system for gaining compliance within the USDA for standards and practice. Again, these features could be applied to all renewable energy services.

I agree with your report. A feed-in tariff should be open only to resources and technologies meeting defined, eligibility standards. A feed-in tariff incentive should only be available to renewable energy producers that employ standards and practices which are based on the environmental and developmental principles. Thank you.

MR. LEAON: Thank you, Gary. I have

three more blue cards. And do we have anyone on WebEx that is requesting to speak?

MR. FLESHMAN: Nobody has requested. I can ask them if they have any questions.

MR. LEAON: Because what I would like to do is get through these other three cards then we will break for lunch, hopefully by 12:30, and take an hour for lunch.

Okay, the next speaker, Liz Merry.

MS. MERRY: No, I didn't submit for this, it was for the previous question.

MR. LEAON: All right, thank you. Anne Gillette with the CPUC.

MS. GILLETTE: I have two questions, actually. The first question, this relates to integration of the resources. I was wondering if you could address whether European countries or the other areas you have spoken about, how they approach planning for the ramp in regulation services, for example, that's needed for these resources when you don't know or have a good sense of exactly when projects are going to come on line. How you plan for all of the services that are necessary to integrate the energy. The ISO has already indicated that for the -- even for the

20 percent by 2010 levels we are going to need new, we are going to need additional ramping and regulation services. So I'm wondering if you could address that.

MR. GRACE: I think the short answer is we don't know. And it's an excellent question and one that needs to be considered.

MS. GILLETTE: Thanks. And the other question relates to what seems to be an underlying assumption. There seems to be an assumption that generators and developers want a standard offer contract. But in our program we actually started with -- in the RPS program we started with a list of standard terms and conditions. It was fairly extensive. And then it's been kind of whittled away at the request of both developers and the utilities. So there seems to be some resistance, actually, to at least certain standard terms and conditions. So I was wondering how much you have kind of vetted the assumption that generators want a standard contract? Or maybe you don't see that to be an assumption.

MR. GRACE: I don't think that's an assumption that we have made or not made. Certainly the impetus to consider this in the first place has come from, often from generators that we thought would find a feed-in tariff attractive. The question I guess is, what's involved in the contract. Or even if there is a contract. I think there are situations, it's not always a contract. Sometimes it is a tariff.

A lot of the terms and conditions in power contracts are as they are because of the reliance on the products being purchased by the buyer. And it is my expectation that because of the different nature of that reliance equation that a standard contract offering a feed-in tariff is generally going to be perceived as less complicated and less onerous.

A lot of the contract terms and conditions that may be challenging to a generator in being standardized are there because of that reliance and may not apply in a situation where that generator is not going to be held to all the same obligations under a contract. So I think it's a good question but it may be a matter of degree.

MS. GILLETTE: Thank you.

MR. LEAON: Okay, Carl Zichella, Sierra Club.

MR. ZICHELLA: Hi again. I appreciated your emphasis on goals and objective and how to structure these things. I am one of the two environmental representatives on the renewable energy transmission initiative.

It really struck me that one of the big goals, at least from the environmental community in that process, is to help identify the zones that lead to the quickest build-out of the least controversial projects and the best, environmentally best sites.

And a lot of the considerations that you presented seemed to really work across purposes for that, based on the European model. For example, trying to subsidize projects that are based in marginal locations. When we are really interested in limiting the footprint and building and designing the transmission system so we can get the biggest bang in terms of the energy produced from the best, environmentally most responsible places.

Here in this state there is a huge amount of state policy on wildlife and land conservation. That's, you know, part of the multiple goals of accomplishing something like this. You need to sort or think more broadly. It's more of a comment than a question.

And the design of our feed-in tariff, if we are to go this route, we really need to sort of look at incentives for locating projects in environmentally less-sensitive places with a high payoff.

So when we design our transmission system, a feed-in tariff is actually supporting that goal rather than undermining that goal. I think we'll have better public acceptance and more rapid ability to get steel in the ground if we do that.

MR. LEAON: Okay, thank you. Do we have any questions on WebEx?

(No response)

MR. LEAON: No questions on WebEx.

Any additional blue cards in the room?

(No response)

MR. LEAON: Okay, let's try the phones just to make sure that we don't have anybody on the phone. And again, if you are listening on the phone we are going to unmute you. So if you can mute your phones then I'll ask if there are any questions from the phone. Then if you do, unmute your phone and pose your question.

Okay, the phones are unmuted. Do we have any questions from anybody on the phone?

(No response)

MR. LEAON: Okay, hearing none let's break for lunch and let's meet back here at 1;30.

(Whereupon, the lunch recess was taken.)

--oOo--

AFTERNOON SESSION

MR. LEAON: Good afternoon. We are going to reconvene the workshop. If we could have our panelists come on up. I apologize for the tight squeeze up here. We will get started in just a moment.

This is Mike Leaon again. We are just getting settled up at the front here. We did get a note that V. John White, one of our panelists is running late. Also, is David Hawkins in the audience? Okay.

Well, I think since we are running behind time we should go ahead and get started. And are panelists have graciously agreed to come up in front of the room and share their perspective on feed-in tariffs in California. We asked them to take a look at some of the questions that were posed in the Notice and to briefly share their viewpoints. And so with that I would like to open it up for the panel. Does anyone want to volunteer to go first?

MR. VELASQUEZ: I'll go first.

MR. LEAON: All right. If you could -- And as we go along -- I'm jumping ahead of myself. Why don't we have our panelists introduce themselves. Sorry about that. Let's go through name and organization.

MR. VELASQUEZ: I'm Joe Velasquez. I'm the director of commercial and industrial services for SDG&E.

MS. TRELEVEN: I'm Kathy Treleven from PG&E and I work in state agency relations.

MS. BURGDORF: Hi, Marci Burgdorf. I work for Southern California Edison in the renewable and alternative power group.

MS. WISLAND: And I'm Laura Wisland. I am an energy analyst with the Union of Concerned Scientists.

MR. LEAON: Okay. And what we would like to do here with the panelists. We'll hear their perspectives. We might have a little follow-up on that amongst the panelists and then we'll open it up to questions from the audience. Okay.

MR. VELASQUEZ: First of all I want to thank the Commission for inviting SDG&E down here to be able to share its perspectives on this important topic, feed-in tariff.

And first of all I want to say that SDG&E supports the use of the feed-in tariff for small, renewable technologies and to promote solar applications.

The feed-in tariff for small renewables should be expanded, we believe, as well, beyond wastewater and water customers to all customers of both investor owned utilities and publicly owned utilities in the state of California.

It is important that the feed-in tariffs, though however, be designed and applied properly so they produce the results that are in the best interest of our ratepayers.

SDG&E believes that a feed-in tariff should be generic and apply to all new small technologies equally. Setting one price puts all technologies on the same footing. That rate could be price differentiated and should be price differentiated.

Limiting the feed-in tariff to new facilities would be consistent with the practices in Europe.

However, if a feed-in tariff is designed specifically for a technology such as new solar PV, as has been established like in Europe where there is a significant premium that is attached to the rate, then we believe that it would be a mistake to apply that rate to all technologies. In that case you would be -- customers would have to be overpaying for some of the technologies and that wouldn't be in their best interest.

SDG&E also believes that a feed-in tariff may be effective in capturing new solar opportunities, such as those from customers who wish to invest in solar PV but do not have the load behind a particular meter or location. The current regulation does not provide them with the incentives to go after that particular opportunity. A feed-in tariff would provide those opportunities and would provide them with the financial incentives for these customers to develop those opportunities.

SDG&E also believes that the current 1.5 megawatt limit in the Commission's decision implementing AB 1969 is reasonable. Projects less than one megawatt cannot participate in SDG&E's RFO and cannot connect to the Cal-ISO grid.

Therefore a feed-in tariff is a reasonable way for these eligible projects and of this size that are located within the utility's service territory to participate in the state's RPS goal and be compensated for their energy.

However, systems greater than 1.5 should continue to participate in SDG&E's competitive RFO solicitation process.

Providing a feed-in tariff for larger projects eligible to participate in the competitive RFO solicitation would interfere with that RFO process, potentially driving up costs to ratepayers and make resource planning more difficult.

SDG&E believes that a formal, competitive RFO solicitation process is a better way to ensure that SDG&E's bundled customers are paying competitive prices for their renewable resources and obtain a resource mix that is consistent with our long-term resource plan.

To better ensure that renewable energies procured through a feed-in tariff are quantifiable and can be used for planning purposes, SDG&E believes that feed-in tariffs should require only a full buy-sell arrangement, as it is in Europe. Selling the excess, if and when it is ever available, as currently adopted in the Commission's decision implementing AB 1969, diminishes both the value of the resource to the utilities, customers, and the ability for the utility to use it to meet its resource plan.

Until we have more experience with the feed-in tariff the program should be capped at a statewide level proportional to the cap established by the Commission's decision implementing AB 1969.

This cap should be adjusted for each utility consistent with their share of the statewide electric load. For San Diego that's about -- if you look at only the IOUs a little bit over ten percent. If you include the publicly-owned utilities it's about, between eight and nine. And the overall program cap would limit any unintended consequences of over-subscription. And we heard some of those consequences this morning from the presentations.

SDG&E also believes that participation in the California Solar Initiative should not necessarily disqualify a customer from participating in the feed-in tariff. In our view this is consistent with the current practice of having customers participate in both the California Solar Initiative and the utility's net energy metering program.

However, SDG&E agrees with the current

policy that customers should not be able to participate in both a feed-in tariff and net energy metering.

Lastly, we believe that any feed-in tariffs or policy recommendations adopted and implemented should be adopted and implemented statewide across both investor-owned and publicly-owned utilities.

Also any RPS-eligible energy and resource adequacy benefits should accrue to the load serving entity in that service area.

And any above-market costs from a feed-in tariff program should be shared by all customers.

So just to summarize. A feed-in tariff must be in the best interest of all our customers and applied statewide.

A feed-in tariff is ideal for new, renewable systems 1.5 megawatts and below.

The competitive RFO process for systems greater than 1.5 can best assure our ratepayers are paying competitive prices for that energy.

To provide value a feed-in tariff should require a full buy-sell requirement and any incentives or subsidies of a feed-in tariff should be borne by all customers. Thank you.

MS. TRELEVEN: I'm Kathy Treleven, PG&E. Thank you, Commission, for this chance to talk with you today. We appreciate the depth at which you are looking at feed-in tariffs. And we continue to see such tariffs appropriately structured as a useful tool in accessing small renewables, probably under 1.5. Perhaps somewhat larger generators as well to the utility system.

But for larger generators, however, PG&E believes that a competitive process remains the appropriate way to add renewables to our system. Not only does the process control -- encourage lower costs but it also allows for tailored terms and conditions. Anne had mentioned earlier today that those tailored conditions might meet the needs of the utility or there might be some that would meet the developer's needs.

Using competitive solicitations over the last four years we have contracted with 2500 megawatts of renewables. Everyone here knows that there are some challenges getting all of that renewable resource online. But to us those challenges seem far more to be in the transmission area. To the siting area. To be related to the tax structure. And to the escalating cost of materials worldwide. Much more so than the lack of a standard contract for large entities.

The objective of whatever feed-in tariff program we pull together should be clear at the outset to figure out what it is we really would like to obtain. In particular I would like to hear the staff and the Commission's ideas about how such a tariff or other changes to contracting structures could lead to parity for the IOUs and the municipal entities in terms of both of us getting to similar targets.

As we said last year, there might be some advantage to creating feed-in tariffs for units larger than 1.5 megawatts. I can't tell you what is exactly the right number to -- in which you can balance the tens or hundreds of thousands of dollars associated with negotiating contracts against -- against the needs to tailor contracts.

I will mention that 20 megawatt plants and larger have revenues in the annual level of millions of dollars. And those revenues -- And at that level I think all of us believe that the contracting costs are a small percentage of the real costs of getting those plants online.

I'm sorry that I haven't been able to provide you with a speaker today that is close to our renewable contracting experience. That may limit what I can respond to in terms of questions but we try our best to respond to everything in our written comments and to other things that come up today. Thank you.

MS. BURGDORF: Hi, Marci Burgdorf with Southern California Edison. Mimicking the statements by the previous two utilities in that we do believe and support a feed-in tariff that is appropriate for small generators. But we also believe in the competitive solicitation process and we should not be developing larger feed-in tariffs that would compete with that process.

It has been very successful for us so far. It's very robust and successful. We've talked a little bit about that today. And it's really produced benefits for both the buyer and the seller. It allows us to work directly with the seller. We go through a negotiation process, there's contract terms and conditions that are developed. And that's really what the benefit is in working with generators, larger generators.

In any feed-in tariff it's really

important that we look at developing the objectives. What are we trying to achieve. For Edison as well the biggest to bringing renewables online is transmission constraints. A large feed-in tariff is not necessarily going to bring those renewable projects online any quicker.

What we really should be focusing on is what are the ways that we can improve the siting and permitting processes and what can we do. Those are the kind of things that will help us achieve our goals more quickly.

So let's see. So again, in support of the smaller generators. Edison has developed the biomass standard contracts. There's three tiers of projects, up to one megawatt, one to five megawatt and then six to twenty megawatt.

We have developed those voluntarily and we would encourage the Commission to encourage the utilities to do more voluntary type of feed-in tariffs that would more appropriately meet the individual utility business objectives and really let us look at what's happening in our specific territories and figure out what are the best ways to address and meet those needs.

I can tell you with the biomass

contracts, the four contracts that we have signed are all below the five megawatt range. We really feel that up to five megawatts would be legitimate.

Typically the smaller generators have a problem competing in the solicitation process. They don't necessarily have the expertise or the resources to be able to compete successfully. And they are the 1.5 megawatt. Anything below 1.5 megawatt is limited in competing at all.

So the smaller generators can connect at the distribution level. So you are therefore alleviating a lot -- some of the transmission issues.

MR. LEAON: All right.

MR. WHITE: Well I accepted this invitation to speak with a caveat that the organization that I lead has not developed a formal position on feed-in tariffs because we have been so busy with the implementation of AB 32 and the scoping plan.

We are pleased to note that the scoping plan included the recommendation that we and others have strongly advocated for, a 33 percent renewable portfolio standard across all load serving entities by 2020. So that's the number one planning assumption that we are starting with here.

The other thing is that we are working on removing the regulatory underbrush, the current California RPS, which has led to the distortion in the market that we see.

But before we can get to feed-in tariffs I think we have to have a fundamental reappraisal of the cost and the value proposition for renewables. Because if we don't, we aren't honest with ourselves about what the value of renewables are, then we won't possibly be successful in either a conventional, competitive solicitation or in a feed-in tariff.

The problem with the early work done on the feed-in tariff, it was to the market price referent, with no value for the renewable attribute. Nobody in the world does that. That's just like dumb, okay.

So we start with the notion that the right place to start talking about renewables is some kind of reference to fossil price, plus RECs, plus other value like time of day and location and so forth.

But here it gets to the critical failure of our current procurement process. It's that we have badly misjudged the price of natural gas, okay. We have forecasted the price of natural gas and built those forecasts into our assumptions of how much we could buy renewables.

Because the whole California RPS program is based on being sure we don't pay too much for renewables. Which has led to a distorted bidding process. A lot of gaming in my opinion. People bidding projects that aren't getting financed. Which is the principal attribute of the European system as projects get financed.

So we start from the proposing that feed-in tariffs are a metaphor for being successful in renewable procurement, okay. Now they have their attributes and they have their critics in terms of paying too much. But the problem in California hasn't been paying too much, other than paying too much for natural gas.

And the rate shock that we are headed for later this year, which will be substantial, is not a function of all the RPS contracts that have been signed. It's a function of all the RPS projects that haven't come on line and displaced the gas that they are supposed to displace. So now that the gas price is $13, now the ratepayers are paying the piper and there's going to be hell to pay.

So we begin with that set of facts and circumstances. And then you look at the European model and what people basically said is they erred on the side of getting projects built. Now a couple of features about the feed-in tariff that we understand has been developed in Spain that I think might be appropriate for California. A couple of attributes.

One is they are technology-specific. You don't have a feed-in tariff for wind or PV, it's the same as for CSP. All right? Because they have different costs and different value to the ratepayers. So we're looking at technology benchmarks, okay.

And if we get rid of the illusion that the price of fossil fuel has anything to do with the cost of renewables, the projected cost of fossil fuel especially, then that's all you've got is technology benchmarks. It's what does stuff cost. What's a fair and reasonable price for a CSP project using a technology like parabolic trofs. What's the projected price and what are the guarantees that go along with some of the other technologies. So that's the kind of world we are going to head for.

And in that kind of a world the feed-in tariff has some virtues. Now one thing about Spain that I think is important. It had two attributes that are very different. One, they required deposits for their transmission queue. So none of this getting in the line and waiting and then selling it to somebody else later, like buying tickets. You know, having somebody wait for you in line to buy tickets to a rock and roll show. That's the way the ISO queue has sort of worked up to now. So in Spain you have a million dollar deposit. A million Euro deposit. That kind of sorts the serious from the unserious.

And then the second thing they have is they are buying a specific quantity of the resource. So in Spain they had a very generous CSP feed-in tariff. It was 500 megawatts worth. So they got 500 megawatts. And then they said, well okay, that's enough at that price. Let's see what the prices are and so forth.

So you end up looking at what things

cost and you involve the bankers. See, our system up to now has been utilities and developers. That's who has created our RPS contracts. There's no bankers in those conversations until after the PPA. But the bankers are the ones that determine what gets built, okay.

The other thing about a feed-in tariff is that a feed-in tariff allows the utilities to participate. And one of the issues, it's a little subtext in all this stuff. I am very grateful to hear that our friends from the utilities are eager to support competitive solicitation because the world I thought we were living in was mostly bilaterals. And the bilaterals were the ones that didn't apparently have reference to the above-market fund at the PUC. Which means only a dummy is getting the competitive solicitation. Everybody is going to want a bilateral. So what we need is the same.

In the meantime what we are getting to the new system, whatever it evolves to, we've got to have equality between competitive solicitations and bilaterals. We have to have no more of this above-market fund and RPS/MPR business. That doesn't have anything to do with anything other than the past, okay. What we have to focus on is how to get these resources built and online and how to pay the best price we can. And how to get that price to be lower by building them bigger.

So as we move to that kind of system I think the feed-in tariff becomes an opportunity to experiment a little bit and try some things and see how it works. I do believe you are going to have utility-specific things. But, you know, I actually think we've made some progress in the last year through the Energy Commission's putting us on the agenda, having meetings like this, have an IEPR. Having Edison come forward with the wastewater stuff that gets us some practice.

Now we even have Edison proposing its own feed-in tariff for itself with the PV proposal. And I think that's progress. Because if Edison can pay itself $3.50 a watt to build PV then that must mean that PV is worth $3.50 a watt. And others that can do that same price ought to be afforded the opportunity to compete at that price. It makes no sense to have only a utility be able to get that price. It makes sense for everybody to get that price because that's what the value looks like and that's their healthy exercise, I think, to look at this.

On the other hand, if it were to go forward with no feed-in tariff. Now we have got a legislative bill being discussed, SB 1714 by Negrete McLeod, in which we're talking about raising the allowable for PV. This is like CSI, bigger than CSI projects. So apparently they're talking about going between three and ten megawatts for that program. Now three megawatts is low, five megawatts is what we just heard, maybe five is a good place to start and see how we do.

Because I think one of the urgencies that you saw -- If you haven't see the press coverage from Miami you need to see a couple of articles that came in. One is Governor Schwarzenegger's comments about his views about how we should be going and what he's been learning from hearing about the European experience. A quite striking statement I think of where the Governor's head is at.

And then the other is the appearance by Hermann Scheer from Germany. Who got a standing ovation, as he often does.

I am basically saying, just keep it

simple, you know. Give customers the ability to come and put these things on and plug into the grid.

Now we have a much more complicated system and I absolutely agree with Edison about the transmission system. We are committed to doing that work, we're part of the RETI process. And I will say that if we get to a list of early stage transmission projects the next thing we are going to need is procurement to fill up that transmission that we are now building, okay. We have got to match the transmission projects with procurement.

And if we're in a hurry we shouldn't be afraid to look at feed-in tariffs because they will require ongoing oversight and review. One of the things I think we've seen from the other places that have them. They are very much more transparent than anything like what we have.

They have to have debate about what the value is. And maybe the prices that we need to pay to get projects built is something that we need to find out instead of trying to pretend what the price of renewable projects are. We need to find out what the price of renewables are and get about building them.

And I think we are at a moment where we can start doing some interesting things. And not throughout the current system because I think we've got a lot of projects in the queue and a lot of contracts being negotiated. We don't want to disrupt that. But when we look post-2010, I think we have an opportunity to do some more creative things than we have been doing and to borrow from the experience in other places and see what works.

So those would be some of my thoughts, knowing that there's a lot of caveats. A lot of people in my organization might disavow these comments. But I think these are some of the issues we need to think about and these are some of the choices that we have to concentrate on.

MR. LEAON: Thank you very much. And we didn't get a chance to introduce you earlier. V. John White, executive director of CEERT. Thank you for your comments.

MS. WISLAND: Hi, this is Laura with UCS. I wanted to first thank the Commission for giving us this opportunity to talk about such an important and timely issue. And like CEERT, UCS is just beginning to form our thoughts and policies on this issue so I look forward to hearing from everybody else.

But I did want to share some just general statements. First of all that UCS is very supportive of the existing RPS program and that we look forward to working with the Energy Commission and the Public Utilities Commission to reach our 20 percent goal and the stated 33 percent goal.

And we feel like a feed-in tariff program may have a place within the existing RPS program but RPS goals have a very important place. They send a significant signal to the market that procurement demand will be there. And that RPS goals should be looked at like a floor and that a feed-in tariff should be designed to complement and actually surpass the stated goals.

We also believe that the two main issues slowing down renewable procurement in the state right now are transmission and siting and that feed-in tariffs won't necessarily fix these issues. We do believe that they could significantly reduce transaction costs, which are probably relative -- a bigger relative burden for our smaller developers. So starting something small does make sense. We don't have a specific number.

And I also just wanted to reiterate the statement made by Carl Zichella earlier that in moving forward with this transmission process, placing a value on the areas that make sense for transmission, both in terms of a cost perspective but also additional environmental values is important and should be reflected in any tariff.

MR. LEAON: All right, thank you very much. I appreciate the insightful comments from our panelists. And before we open it up to questions I did want to give each panelist a chance to amplify their remarks or comment on some of the things that we've heard from other panelists.

(No response)

MR. LEAON: No? No takers? Okay, all right. You'll have to be subject to grilling by questions now then. Okay, let's go ahead and open it up for questions. First let me ask if we have any questions from the dais?

(No response)

MR. LEAON: Okay. Do we have any blue cards in the room?

(No response)

MR. WHITE: No blue cards. Okay. Do we have any WebEx questions?

MR. FLESHMAN: I'm checking right now. Nobody is raising their hand, yes.

MR. LEAON: Okay. We do have one blue card coming up.

MR. LEWIS: Craig Lewis from Green Volts. I have to be careful here because PG&E is a customer of our's and we hope to do business with all the utilities.

Green Volts is a solar technology company. We also are vertically integrated, we develop our own projects. And I just -- I think it was hinted to by Marci that there is an opportunity here at the one to 20 megawatt range for a feed-in tariff to help fulfill where we currently have a very large, programmatic gap in California.

One megawatt and below is well-covered by the CSI program. Twenty megawatts and above is relatively well-covered by the RPS program. We think that RPS actually satisfies the large projects quite well. But in the one to 20 megawatt range, especially where you can interconnect at distribution level voltages, as I think that was Marci's point. There's locational benefits value and there's large opportunities to develop renewables that are currently not being developed. We are not stimulating that part of the marketplace because we don't have programmatic coverage there.

It's said that the RPS program fits that part of the market, that market segment, but it really doesn't. The transaction costs associated with navigating through the RPS-RFO gamut are significant. By the time you are done proposing, by the time you are done negotiating, and by the time you are done contracting, you are a couple of hundred thousand dollars -- you could be $500,000 paid out in that process. It's significant.

And as a developer I just want to make sure that that point is really well understood in this room. It's a very significant cost. The transaction costs are very significant. A standard offer contract eliminates all that. And as a developer, and speaking for a lot of developers, I don't know any developer that wouldn't want a standard offer contract.

There's been some comments earlier that maybe developers don't want a standard offer contract. I don't know a single developer that wouldn't jump at that.

MR. WHITE: Maybe we should call it a standard offer contract instead of a feed-in tariff. Because that is actually something that we have some precedent for doing from years ago and it is actually where the bulk of our renewables came from. And it also an idea that actually inspired, one might say, the feed-in tariff approach.

So if it's a standard offer for a fixed amount of megawatts and particular attributes, maybe that's the way to think about it.

MR. LEWIS: So I don't necessarily have a specific question. I do appreciate all the comments and especially John White's. I think, John, you really provided a perspective that wasn't reflected here and I'm glad you showed up.

MR. WHITE: I would urge you to speak with Senator Negrete McLeod's office right away. She has got a live bill that she is negotiating and the numbers are bumping around three percent. The one thing you might want to do is get the PUC's exclusive authority to go as high as 20 once we get the nuts and bolts figured out about doing three to five. Because I think you're right, we don't really know what the right number is other than below 20 probably isn't covered much by the RPS.

MR. LEWIS: Yeah. Just in response to that particular comment. There have been a variety of discussions, maybe through another party been in discussions on the SB 1714 is the bill you're referring to. And I think there's a lot of resistance from some of the parties that are involved in that discussion. I think some of the utilities are in that discussion and it has been very difficult to raise that cap.

So I don't know if 1714 is going to be the bill that does it but I think that there is a lot of receptivity in the Legislature to get it done next year if not this.

MR. WHITE: If you look at the, if you look at the level of urgency that is expressed in some of the public statements that have recently come from the administration -- I think this is a matter of sort of changing the dynamics politically.

We're sort of in a different place, you know. We're short on 2010. Some of these projects we're talking about could really help us make up that shortfall in a pretty quick amount of time. I mean, I don't know how soon from adoption of a, shall we call it a standard offer renewable tariff instead of a feed-in tariff. From the time we had adoption of such a tariff, how soon could we get projects in the ground? That would be something to bring to the discussion.

MR. LEWIS: I think that point deserves reemphasis. That the one to 20 megawatts will be extremely well-served by a standard offer feed-in tariff contract. I'll combine those two concepts. Because I think the standard rate is also important. So the defined rate and the standard offer are two of the fundamental concepts here that need to be involved in a feed-in tariff program.

And this one to 20 megawatts can be stimulated. This marketplace that is currently not being stimulated by programmatic coverage can be stimulated significantly and help California achieve the objectives of the RPS program. And to do it in an area where you have the locational benefits value. You're generating close to load, you're interconnecting at distribution level voltages, and you're providing residual value to the ratepayers above and beyond what they are getting on larger projects.

MR. WHITE: Has anybody thought about the munis piece of this? Because my friends from the investor-owned utilities are always going to want equivalent requirements on the municipal utilities.

I know that LA has looked at the possibility of sort of combining a CSI rebate incentive with a power purchase agreement combination. And the power purchase agreement would be at a wholesale price that reflected the value of solar. Like what they think CSP might be worth is what the PV guys would get after the first few years of the rebate.

It seems that one thought about a feed-in tariff, Energy Commission, since I think you are going to be getting some responsibilities shortly to help oversee the munis' compliance with the new, more robust goal, is to think about how to bring the munis into the conversation. Because the more you ask the IOUs to do the more they are going to want you to be able to say that the munis are facing the same -- provided with those same opportunities.

MR. LEWIS: And Edison I think has been very forward in its thinking. It recently applied for the solar PV program at the CPUC. It's a wonderful program, it's a wonderful application. And they definitely got the locational benefits concept nailed down.

If you read that application it is very clear that there's significant value from generating close to load and interconnecting at distribution level voltages. So that's one case in point. Edison I guess has been kind of out in the forefront. You also have the -- Marci, I bet it was your idea.

MS. BURGDORF: Of course.

MR. LEWIS: The Southern California Edison biomass program. It's a feed-in tariff. It goes up to 20 megawatts. Again, a perfect case study. So the evidence is out there that this really makes sense and we just need to get it together here in California and make it happen.

MS. BURGDORF: Can I just make a comment, up to the 20 megawatt for the biomass standard contract. Those are three different contracts. So there are specific performance requirements up to 20 megawatt that you don't have with the one megawatt or up to five megawatts. So there are additional provisions that are included as part of that contract.

So we are, we are finding that there are some people that would prefer to go through the competitive process because they are able to negotiate terms a little bit better.

MR. LEWIS: And I think the pricing is probably the issue because it's MPR. So biomass programs can't make it happen.

MR. WHITE: Is it possible to have, to have some equivalent opportunity on that Edison proposal? To have both what Edison is going to do with its own owned projects and then maybe open that up to allow others to participate at roughly the same terms? Because I think one of the virtues of the feed-in tariff in Europe is that it's open-ended and competitive in the sense that anybody can bring a project forward, whether it's a utility or whether it's a private party.

And it seems to me that maybe we could do some experimenting with this application and maybe figure out a cap or something that would allow a significant amount of large-scale PV to be provided, both by the utility as well as by the private sector if in fact the terms can be roughly made the same.

MR. LEWIS: I think that's a great policy idea. The one caveat I would say is I think the Edison program should be a starting point, not a ending point. Edison obviously -- Southern California Edison obviously is a huge purchaser and has significant purchasing power. And they obviously have the opportunity to shop around for the lowest cost, the absolutely lowest cost provider. And this shouldn't be a program that only benefits one company. In other words, the lowest cost provider.

So with that caveat in mind I think that the Southern California Edison program is a wonderful starting point and shows the light, so to speak, in terms of how to implement this program. Thank you.

MR. LEAON: Thank you very much, Mr. Lewis.

MS. TRELEVEN: If I could add something more. Thank you for your comments on transaction costs and the mid-range power plants. I just wanted to emphasize that in my research in preparing for today generally we were focused on the Energy Commission's intention to talk about feed-in tariffs for the larger folks. That it was emphasized, to me, for the larger folks.

There were a lot of folks who wanted contract flexibility. You know, in fact, it was reinforced for me today when Anne said the very same thing. Having the perspective of looking at three different utilities' negotiations.

But I did want to let you know that I will take these thoughts home. I think we need to do a little more thinking about the mid-range folks.

MR. LEWIS: Great. And part of my motivation to come up was to definitely make sure that the developer perspective was reflected. Because I was here for Anne's question and I was a little surprised by it. And I was more surprised by the lack of a firm answer to it, which is developers would absolutely jump at the chance to have a standard offer arrangement here. So I'm speaking after -- I'm very broadly interconnected in the developer community. It's a feature that is desired heavily in the developer community.

MR. VELASQUEZ: I just wanted to address

a little bit about the cutoff as well. I think that we have just begun. My dealing is mostly with commercial/industrial customers. They are telling me, you know, we want to be able to build solar primarily and be able to sell into the grid. And most of the projects we're looking at, I think primarily all of them, are below 1.5. Of course they are a different type of customer. They are usually an end-use customer and they are building solar.

You're talking of investment if you look at the current cost in the, for example in the SGIP program. Which they have a long history of keeping up the cost. Those projects were about $6,000 to $7,000 dollars a kW. So we're talking about investments of around 14 to 15 million dollars.

That's a significant investment, even at 1.5 megawatts. They are significant investments. There is going to be some transaction costs any time that you exceed that amount. But these are not trivial projects. They are rather, fairly large projects.

The other thing I think that the feed-in tariffs provide that we're looking at is that customers right now on net energy metering can only see the benefit if they have the load behind it. Some customers say, you know, my load is over here but I have a huge amount of real estate over here. So this is another opportunity.

If you keep it at 1.5 megawatts we will still be able to find those types of projects. So I think that you'll see before you want to increase the cap that there's going to be opportunities at this level.

The other thing is that SDG&E, if you look at the caps, the previous cap for wastewater was 250 megawatts. I think SDG&E's portion of that was somewhere around in the 23, 24 megawatts because we are significantly smaller than our counterparts to the north. They're four to five times larger than we are. So a 21 megawatt project would probably just saturate our cap. So that's another reason why it might work for Edison and not work for SDG&E. I just wanted to provide those differences.

MR. LEWIS: And if I could just respond to that a little bit here. I would say that the argument for -- I assume you're talking about the AB 1969 base feed-in tariff program. And to my knowledge there hasn't been a single project that has even been applied for in that. Maybe Anne could answer that question. I'm not -- Somebody from the CPUC might be able to answer that.

Don't know. I'm pretty sure there has not been. And that's pretty strong testimony that it's done work. There are some flaws to the AB 1969 base feed-in tariff design.

MS. BURGDORF: Actually the contract was just approved about two weeks ago so we really haven't had an opportunity to implement that in terms of signing contracts.

MR. LEWIS: Well the CPUC --

MS. BURGDORF: The water, the water crest tariff, AB 1969.

MR. LEWIS: AB 1969. I think that was more like about six months ago, wasn't it? Somebody?

MR. VELASQUEZ: I think there's a decision and then there's implementing tariffs.

MS. BURGDORF: Right.

MR. VELASQUEZ: And I think the lady from Edison is talking about implementing tariffs.

MS. BURGDORF: The implementation of the tariff just came through two weeks ago.

MR. LEWIS: Okay.
MS. BURGDORF: There's time in the regulatory world --
MR. LEWIS: Sure. We can --
MS. BURGDORF: -- to move things along. And so --
MR. LEWIS: We can watch that. My guess is that based on the way that program is designed there's not going to be a lot of uptake on it. People are way better off just scaling it to one megawatt being behind the meter and going in on the CSI program.
So if you're going to make this program viable you need to raise the cap. You need to see if you need to do something with the rate. MPR is not going to attract a lot of solar business, as I think you pointed out there, Joe.
But the one to 20 megawatt range is ripe for a feed-in tariff. We can really get it done right in California. And I think it's a beautiful place to start because you can leave the CSI program alone. You can leave the RPS program alone. The RPS program was designed --
MR. WHITE: We don't want to leave the RPS program alone because it needs to have some

trimming of the underbrush. So I think that we can continue working with what we've got but I don't want to condemn the large projects to the level of uncertainty and performance in terms of delivered megawatts that we have today. And I think that's really important.

MR. LEWIS: Sure. My point --

MR. WHITE: Because we really need a different, we need to think about what the reasonableness reviews are going to look like. Because ultimately the right benchmark for renewables is not the price of fossil fuel, it's just not. It could be a short-term formula, it could be RPS, it could be MPR plus RECs. But the idea that you are going to sell renewables for the MPR would suggest that you are going to confiscate the RECs and that makes no sense.

So I just think -- I understand that we may not be ready to go to a feed-in tariff for the large systems yet. But if we continue to fall behind in terms of delivered projects we ought to look at it at least as a way to jump start certain segments that we really are counting on to deliver lot of megawatts that haven't shown up yet.

MR. LEWIS: Yeah, that's exactly my

point. The one to 20 megawatts has a huge opportunity to bring megawatts on. And it's a deficient market segment. There's deficient programmatic coverage there. And we've got a great opportunity to bring that programmatic coverage through a feed-in tariff and it can show us the way for expanding that even higher in the future.

When I said that the RPS program is providing good coverage to the larger deals, the over 20 megawatt, I'm really talking about the fact that that program is designed to offset 500 megawatt combined-cycle gas turbine power plants. Clearly those are large projects and they're transmission interconnected large projects.

So at 20 megawatts and below you can be interconnected at distribution level voltages. You can get the advantages of generating close to load. You are avoiding transmission losses on the transmission grid and partially on the distribution grid as well. So I see it as a huge opportunity, one to 20 megawatts a feed-in tariff, standard offer and locked in.

MR. WHITE: And -- Excuse me.

MR. LEAON: If I can just interject for

our panelists, for the folks that are on the WebEx. If you can identify your name when you make a comment it would really help them to keep track of who is speaking.

MR. WHITE: This is John White again. I was just going to say that there is some work that was done by the Americans for Solar Power, called the Waterfall Document, that got to some of the behind the meter and the grid benefits of PV. I think that was a very powerful document. And it was very well peer reviewed.

The other piece of work was recently done by the fuel cell industry using the same consultant, the same methodology. They looked at the benefits that could be derived from fuel cells in terms of the benefits to the grid.

And I think ultimately when you are doing feed-in tariffs you have to get them with the value you're providing as well as the costs. And I think to the extent that we can avoid lengthy proceedings where we have to argue about what the numbers are, to the extent we can use existing data that can help us with the value proposition then that's a good thing.

MR. LEWIS: Okay, thank you.

MR. LEAON: Excellent discussion. The next speaker, Jaclyn Marks with CPUC.

MS. MARKS: Okay. I just want to start off with -- sort of express the concern that generators are building to compete, not building to build. So I pose this question to the utilities. Have you considered solutions? And if so, what are these potential solutions to improve the existing framework within the RPS to address these specific concerns that CEERT mentioned today and how to solicit serious projects from the beginning. So an example would be a higher development security or anything else that you have considered to work within the existing framework but to address these specific concerns.

MR. VELASQUEZ: My area of expertise is outside of the procurement area so if there's somebody that's closer to the procurement area I would like them to come up.

MS. TRELEVEN: Mine is also outside of the procurement area. However, I am sure that there's sort of a continuous improvement process going on. And actually that the CPUC itself is part of it and our other PRG members are a part of that. I will try to address that question more in our comments.

MS. BURGDORF: Well, I'll try to touch on it as much as I can. You know, you're always going to have projects like that through the solicitation process. I mean, that's just a natural part. You're going to have projects that, you know, may not be so serious. And part of our evaluation process is to weed those projects out and make recommendations for the ones that are most viable.

So I can tell you that through each solicitation process we learn what works and what kind of projects we're getting, what makes sense. And we make changes to it the next go-round. So, you know, for Edison we go through the least-cost, best-fit analysis. You know, there's evaluation criteria that we build in to each and every project. You know, developers.

It's kind of a backward process because a lot of times they get a PPA to actually move forward and to get financing so you're kind of, sort of going in a circle sometimes. But for the most part, you know, we work as closely as we can with the developers. We have contract managers that are on top of each project.

So, you know, I guess the best way to answer that is, as we go through the evaluation process we look, there's different and new things that we add to each evaluation to make sure that we are getting the most viable projects.

MS. MARKS: Thank you.

MR. VELASQUEZ: I want to add one thing too. That spurred a thought. Before coming here I also tried to do a little bit of research about how procurement --

MR. LEAON: And please -- I'm sorry. Please --

MR. VELASQUEZ: Oh, I'm sorry. I'm Joe Velasquez from SDG&E. That just spurred a thought. Is that, when we asked, how do I get customers to -- or how do I get the offers to actually go through. And as I understand, that through the RFO process there might not be a deposit. I'm not sure if there is one or not. But there is performance-type of conditions that are put on to try to make sure that the projects move.

As we saw from the earlier presentation that was put together by the Commission, there's a lot of it being contracted, it's just not a lot of it being developed. So I think that that is probably an area that probably needs to be looked at is performance.

MS. MARKS: So from the utility perspective do you believe that the current RPS framework, if improved, can address the concerns that CEERT has expressed today? Or perhaps we need to pose that question to the procurement folks.

MR. WHITE: Let me try to anticipate the answer. I think the answer is that the current structure ties the utilities' hands as well as the developers' hands and that everybody is better off with a simpler set of constraints.

I think the combination of the MPR plus the above-market fund and the uncertainty around what that cap is or isn't, all of that constrains and it's the wrong lens. I think if we start looking through the lens of what it takes to get projects built and not just contracts signed, then I think we'll get to the right answer.

I think the utilities have a lot of experience in the current procurement process about what they would be able to do if they weren't constrained in the way that they are at the moment.

MS. TRELEVEN: You know, I would have to say that my sense from the procurement folks is that things are working. Things are working slowly. And that the problems, in a way, don't have much to do with standard offer contracts but have to do with tax credits, interconnection queues, transmission build-out. And that those questions are slowly and deliberately getting resolved.

MS. MARKS: Thank you.

MR. LEAON: All right, thank you very much. Do we have any more questions in the room? It looks like we have one more.

And let me ask, do we have anything on WebEx? No, okay.

MR. BROWNING: Adam Browning with Vote Solar again. I just want to address this to the utilities. As you -- I realize you are not speaking from a procurement perspective. But as the levels of renewable market penetration increase, up to 30 percent and hopefully much higher than that, do you see any negative implications of not using a solicitation process but having a standard offer, kind of must-take process? Especially at the high levels of market penetration. Is that clear?

MS. TRELEVEN: Maybe I could start it. You had mentioned earlier the intermittency problems that we are already starting to see. And those of us who have been in the utility world for awhile also know of -- have seen two tranches of problems with large standard offer contracts of negotiating situations where we had to buy an awful lot of power at a high price. Of course there are concerns on standard offers. And I think that Bob touched on a lot of those concerns.

MS. BURGDORF: This is Marci with Edison. So you're asking, what are the negative implications of not going through the solicitation process?

MR. BROWNING: Are there any?

MS. BURGDORF: Well, in a competitive process you have a competitive bid and you have competition in terms of pricing and technology. So what we're getting out of the market is what the market can bear and we're getting the best of the best that's available right now.

So, you know, I think price is probably -- you know, the price competitiveness is the biggest thing that comes out of that. And you wouldn't necessarily have that with a feed-in tariff. You're creating --

MR. BROWNING: But in terms of like grid management issues. It just seems to me, especially at high levels of market penetration and renewables, which are intermittent and non-dispatchable, you are also going to need to be able to manage your non-renewable resources to best complement what you are getting in.

And it seems to me that a solicitation process might be a better complement to your overall grid management rather than just throwing it off-route and having to accept everything that comes in, not knowing whether it's going to be overwhelmingly wind, overwhelmingly solar with very different generation profiles.

And John too, if you have some thoughts on that.

MR. WHITE: In Europe they separate the two or three different kinds of tariffs into specific amounts. So, you know, you're not -- You don't have to like have a must-take for an unlimited amount. That's the first thing.

Second is that I think the grid

management issues are going to have to get settled anyway. And this has actually been a key issue. There has been a lot of wrangling and posturing about integration costs. And in the end we just need to get all those.

The Europeans have integrated large amounts of intermittent resources in the northern part of their grid. The Spanish grid manager is directly involved with the ISO. Excuse me, with the feed-in tariff. That there are significant deposits required in Spain that are not now required here.

So I think obviously the grid manager has got to be coordinated. And that would probably be settled more by how much you bought in a given period of time rather than whether you bought it through a standard offer or through a negotiated solicitation.

MR. BROWNING: It is almost like using a standard offer offer in more incremental ways that almost resemble an RFO.

MS. WISLAND: Can I just add something? This is Laura from UCS.

We talked earlier about setting the P and not knowing the Q. So that's the big question. If that's really unknown is that going to cause a lot more uncertainty? I agree that the grid issues are going to have to be hammered out no matter what. But if there's a high level of market penetration is that additional uncertainty going to create more problems?

And I think Anne brought up that question and it wasn't really answered. And I'm wondering if there's anyone from the ISO in the room who could talk about this? There's not.

MR. WHITE: Unfortunately David is not here.

MS. BURGDORF: You know, anytime -- This is Marci with Edison. You know, with a feed-in where we are just buying anything that shows up you run the risk of an over-surplus in certain areas, which absolutely has impacts to the grid and reliability. And if those are intermittent resources you have even other issues that you have to look at.

So the competitive process definitely allows us to get a wide range and variety of technologies and sizes.

MR. VELASQUEZ: And I think we -- This is Joe Velasquez. I think that we've kind of said this earlier on. You have customized terms, you know. That's what you're allowed to be able to do under an RFO process. Or at least not customized but basically, these are the needs that you need in order to serve your power needs and for performance guarantees. Things like that are going to be able to provide you with what you need when you need it. Price competitive.

When I talked to the procurement folks that's what they said for the larger ones. That's the best way they have been able to say. That's the way I can guarantee our customers the best price. We have an RFO competitive pricing option.

So that's the other thing. The Q I think was the other element. If you're controlling the P you can't do both. We have a resource plan together. We put together a resource plan. It's a long-term resource plan, a lot of thought had gone into it. How to best be able to procure energy for San Diego.

And if you just have a feed-in tariff how do you know that that tariff is going to be able to produce the results consistent with that plan that you built so it optimizes the resources for your area. Again, with the feed-in tariff you really don't have control over the location either. So the location is also I think an issue that has to be considered along with dispatchability like you mentioned.

MR. BROWNING: Potentially all things that could be --

MR. VELASQUEZ: There's pluses and negatives.

MR. BROWNING: -- handled through a more finely tuned feed-in tariff.

MR. WHITE: If you look at our task as sort of evolving from when we started, you know. This is John White with CEERT. What we started with was renewables on the side and fossil the centerpiece of our procurement. And with the advent of climate and with the advent of extraordinarily high fossil fuel prices the cost-value proposition of that strategy is getting really, really examined.

So if we are going to talk about putting renewable procurement, and particularly large-scale solar in particular, as the center of our matching the peak, the growth with the renewable resources that we can, then the task really becomes how best to get that done. Not whether it's cost-effective.

And I think the comment about the best deal for the customers only holds up if the customer gets the renewable energy delivered. And that's the part that has been missing up to now. Now that's not to say that people haven't tried and that people aren't working hard at it. But it's now become too important to leave to just the kind of uncertain outcomes.

So I believe that the utilities are capable of performing and being freed up from the RPS process to do better than we are doing now. But I also think that the opportunity to have more tools in the toolbox is something worth looking at, particularly if there's a premium being placed on results.

MR. BROWNING: If I may add just one more comment here before stepping down. Marci, if you will allow me to say this without holding it against me too much. But looking forward to seeing your commitment to competitiveness extend, referring to your PV application, extend to that market as well. Definitely I think that that should be open to all market participants. Following up upon your remarks. Thank you.

MR. LEAON: All right, thank you very much. The next speaker, Wilson Rickerson.

MR. RICKERSON: Hi all. It's been a great panel so far. I just had a -- We've talked a lot about PV and also the one megawatt to 20 megawatt. But one of the focuses of the workshop is 20 megawatts and over.

And maybe not starting back from PV, what could be the role, or do you see any role, for standard offer contracts, feed-in tariffs for 20 megawatts and over. The kind of big projects. And is there some room for near-market resources that are not PV to serve as a hedge and kind of have those serve some kind of hedge value or is it problematic?

MS. WISLAND: This is Laura from UCS. Just based on the comments that I heard today from the utilities I don't think at this point that I would say anything over 20 megawatts needs a feed-in tariff right now. It seems like the benefit really is more towards the smaller projects and that we should focus on that first.

MR. WHITE: Well, I think we've got to be a little more open. I think in the end if we're focused on RPS performance streamlining, what everybody is sort of collectively working on. This is John White again. I would say that should be the principle focus.

But as we look forward into the future and we start looking at the transmission zones that we're identifying through RETI and its successor. And we are going to be looking at areas of the state where we are going to anticipate and want substantial, accelerated investment.

And assuming that the grid issues get solved by sort of a direct policy direction from the Governor and the Legislature to get the grid ready for a low-carbon future. And to make the changes necessary to get the ability to ramp and handle the intermittency. Assuming those two things. Then I could see some targeted efforts in areas that are under-represented in the procurement.

If we are not getting procurement that results in projects that are constructed, which to me is the principal -- You know, in Spain what they say is that an announcement is for real when the turbine is delivered in the case of CSP. So when the turbines are being delivered and ordered and honest money is being put up then we'll know we're on our way. And until them I think we need to keep the option open.

MS. BURGDORF: Thanks for the question. This is Marci Burgdorf with Edison.

I think that right now would be premature for us to consider anything above 20 megawatts. I think there's a couple of things that we need to look at, one of them being the implementation of AB 1969. Seeing where that goes, how it works in the market. You know, what we're getting out of it and then moving from there.

I think we need to go through lessons learned so that we don't have the same type of thing that happened in Germany or in Spain where they had to revamp the market after four and five years. So I think that it makes sense for us to do it in a step-up process if we are really seriously looking at going over 20 megawatts for a feed-in tariff.

And if we were to do that, when and if we did that, we really need to consider what is the objective that we are trying to achieve. So are we looking at bringing emerging technologies forward into the market? If that's an objective then we would want to design the contracts specifically to meet that goal. Are we trying to get renewables in a specific area? I think there needs to be a specific objective behind that.

And if we do create it there should be performance standards that are built into the tariff. We want to ensure that the projects are there after four and five years so that there's sustainability, that they are being maintained. So these are all things that would be important elements of a tariff for the larger projects.

MS. TRELEVEN: I don't think I have a more expansive comment for you. I think our focus now has been on the other problems associated with 20 megawatt, getting 20 megawatt and larger plants online.

MR. VELASQUEZ: I just wanted to add one comment. It's difficult for me to at least imagine where you would have the systems that would be the same size and either be able to procure them through an RFO and a feed-in tariff at the same time. I would imagine that if you had a feed-in tariff, as you indicate, above 20 megawatts, how would that not interfere with your

RFO process? How would that not set, let's say, some kind of a floor?

Here you have a feed-in tariff with, let's say. You want to make it very simple. Very few terms and conditions. That's the price. Now you have an offering here with terms and conditions. You've basically, at least from my perspective, you've set a floor. And so you've now, I think to some extent, interfered.

So it's a little bit difficult for me to imagine. If you are going to have one or the other how do you have systems of that size? I think that's why we came down. It's that anything above this size, and 1.5 in our case, would make sense to pursue through an RFO. Anything below that you pursue through a feed-in tariff. But you don't have them conflict.

MR. RICKERSON: Thanks very much. It kind of gets back to that replace, alternative or parallel question. Thanks a lot.

MR. LEAON: Did we have any other blue cards in the room?

(No response)

MR. LEAON: Anybody else in the room care to pose a question?

ADVISOR TUTT: Mike, up here.

MR. LEAON: Yes, Tim.

ADVISOR TUTT: This is Tim Tutt. I just had one question for the panelists, I guess. The feed-in tariff report talked about a variety of things that feed-in tariffs may or may not do in California, including the possibility of feed-in tariffs helping some with transmission problems, helping some with contract failure problems. I'm wondering if the panelists have thoughts on those two areas at all.

MR. WHITE: This is John White again. I think the contract failure problem is the one most worth talking about as an alternative. But that requires you to have the conversation of what amount of money you think these projects are worth. And if we have a really bad natural gas price forecast like we had in terms of the future value on prices then I think that's when they impede that conversation.

So I think the opportunity, as my colleagues have said, is to make some significant changes in the way we're going about buying and evaluating renewables today. And I think to the extent that the least-cost focus is going to continue to govern this I think then that will sort of keep us in the same place. I think we need to start thinking about the best fit as the more compelling focal point. And I think the best fit can reach into some targeted feed-in tariffs, assuming that you are going to continue to get the grid ready.

MS. WISLAND: This is Laura from UCS. I think we need both. I think we need -- I think we need the best fit but I also think that we need least cost within that category.

And that, you know, if feed-in tariffs are going to reduce the incentives for renewable developers to submit contracts that don't adequately reflect the costs of their projects. And yeah, that might help with contract failure and that makes sense.

I don't understand how it's going to help with transmission. I would love to hear more ideas on that.

MR. WHITE: I think that's a separate test.

MS. BURGDORF: This is Marci with Edison. I'm not clear how it would help with transmission unless a feed-in tariff somehow improves the process for interconnection or builds transmission faster. I don't see how that is a one answer to that major problem.

In terms of contract failure. I am sure there's assurances that it can provide but I don't believe that it's the one answer to stop that from happening.

MR. WHITE: Maybe the under 20 megawatts is what helps with transmission.

MS. TRELEVEN: This is Kathy Treleven, PG&E. I am going to take a little leap and speak as sort of an amateur procurement person. It seems to me that one of the more compelling things I have heard today is the fit of some sort of special contracting with transmission areas that we are building up. So I will take that back to the people who really do procurement.

It seems like ever since standard offer contracts were in place in the '80s there were pockets of areas where you had a lot of churn trying to build a number of projects but nobody wanted to go forward. RETI and other discussions are helping us target those transmission areas now but it does still seem like there might be an opportunity to investigate additional ways to encourage contracting in those areas.

MR. VELASQUEZ: We believe there's a big transmission issue with regard to trying to get renewables into San Diego and we have been trying to work on it for a long time now. We think that we really need two solutions there.

With regard to contracting. Probably somebody has better experience than I do. I look at a feed-in tariff on one side. If you have a signed contract on the other, why would a banker like one over the other? I'm just not sure. It's the price but not the certainty, you have the certainty there though. Because in terms of certainty, in terms of --

CPUC ADVISOR ST. MARIE: Why would the price be different?

MR. WHITE: In 1969 the price was the MPR and nobody bid for a feed-in tariff. So a feed-in tariff doesn't guarantee that people build. In Europe the amount of money that the renewables have been paid has been much, much more. So it has taken away a lot of the uncertainty.

My assumption as I started with my remarks is that the first thing you've got to do is get the cost value proposition for renewables right. And we have misjudged them. And so a feed-in tariff doesn't change the need to change the adjustment. You could use the existing process in a much different way. And in fact, without regard to the fossil fuel price as your benchmark, which is what I think we're headed for at some point, regardless.

CPUC ADVISOR ST. MARIE: This is Steve St. Marie from the CPUC. I think it is worth pointing out that that is a fundamental change in the subject that we are talking about today. The distinction between a feed-in tariff and a contract has not been put to -- it has not been our subject with regard to one being more remunerative than the other.

MR. WHITE: It's not a matter of being remunerative. It's a matter that in Europe where we're comparing this to is that they have made a specific commitment and a decision that they wanted to pay a certain amount to be sure they got projects in the ground, and they have. It's not that the mechanism is superior one way or the other. But what I'm saying is up to now, the structure we have been in, compares unfavorably in terms of its results to the feed-in tariff. And one of the elements is the price.

CPUC ADVISOR ST. MARIE: So I think that the presentations that we received this morning that were about the various combinations of decisions that go along the way to deciding whether and how to put in a feed-in tariff, we should put in another arrow which would say, pay a lot more.

And then I think the whole subject changes and we are no longer talking about whether a feed-in tariff is the superior mechanism or not. We're talking about whether paying a lot more would be a superior mechanism for getting people to put more of the stuff online. And I think it is axiomatic that we would get more stuff online if we were willing to pay a lot more for it.

MR. VELASQUEZ: I would accept that.

(Laughter)

MR. WHITE: I would point out that we're paying a lot more for natural gas and not doing much about it. Let's not think that we not paid a price for the decision.

ADVISOR TUTT: Mike, I have another question.

MR. LEAON: Okay.

ADVISOR TUTT: Mainly for V. John. In terms of we're looking at a feed-in tariff for a particular RETI area, as an example. Maybe it's a wind area. And even in that area there might be some range of costs between one wind producer and another wind producer.

The feed-in tariff report talks about I think moderate versus aggressive establishment of the feed-in tariff level. In the aggressive level all of the renewables in that particular area or that particular category would get paid sort of a cost equivalent to the high-cost provider in that area so that you would get a lot of development. Is that what we are talking about here?

MR. WHITE: I don't know that I would do a feed-in tariff for wind in Tehachapi as a first place to start looking at feed-in tariffs. We've got a significant amount of long-term contracts that seem to be moving forward. So I think you've got to judge where to start this by what you're missing. And I think you've got it --

That's the whole virtue of doing it by targeting is that you don't necessarily give every renewable developer the opportunity to get the same high price. There may be a very good reason for competitive solicitations in certain technology sectors.

On the other hand, if you've got technology sectors that are under-represented in terms of the ability to be delivered then you may want to look at them differently. And I think the case of solar is an open question. We have a lot of contracts but we don't have anything under construction.

Although I will note that today AUSRA announced in Nevada that they were building a factory with Senator Harry Reed so maybe there's some stuff at least being constructed nearby. Schott is building a factory in Albuquerque for receiver tubes as well. So there's some sign of vendors coming and making a commitment.

I still believe that the utilities, if freed from the current strictures, and had it made important to them by the regulators, could do a lot with the existing competitive solicitation process. I don't think having to go to feed-in tariffs is the only way to have performance or better success.

But I do think you can target the areas

that you're missing or seeing under-represented and see what you get. One of the things about doing this is to sort of see what stuff really costs and decide if you want to pay for it.

And I think there is some virtue in that but I also think that the German model is very different than the Spanish model in terms of how they went about it and how much volume they had at what prices.

And I think the notion of sort of doing it first with the smaller segments of under 20 megawatts, and then taking a look at your procurement reforms that you have already got in place, and then see what the role of benchmarks are. You know, whether you're doing feed-in tariffs or technology benchmarks, you're going to still have to try to look at what stuff costs and what a reasonable and fair price is and then see what the utilities can do in terms of negotiating.

And the basic decision about feed-in tariffs is how much of a discretion you want to give the utilities in terms of what they're buying and from who. That's the essence of why they're going to want to probably not have feed-in tariffs for big projects. But it is also if the performance on the competitive solicitation model, the bilateral model doesn't result in stuff coming online, then you need to look at these other opportunities.

MR. LEAON: Okay.

ADVISOR TUTT: Let's raise one other example as we're talking about the possibility of utility RPS processes being improved to achieve greater performance. Does Texas serve as a model for that at all?

MR. WHITE: Well, I was just down in Texas. This is John White again. Texas can pick up 5,000 megawatts online really quickly with a very simple system of both compliance penalties, payments and fairly simple requirements. They are starting to have integration issues there on a fairly large scale. So how high they go beyond where they are is going to end up putting them with some of the same issues we're grappling with in terms of transmission and stuff.

I think certainly their initial success is something you want to be grateful that they have done and it was a good example. I think the other thing is just keep looking at other examples and other people's procurement and see who is being the most successful.

Nevada got a project online, you know. That wasn't done with a feed-in tariff, it was done with a contract. So I think the key is getting projects built and how you get that done. And I think there's lots of different choices you can get to.

MR. LEAON: Okay. Any additional follow-up questions, Tim? Okay. Any other questions from the dais?

CPUC ADVISOR ST. MARIE: No.

Okay. Do we have any WebEx questions?

Let's give the phones a shot. If you are on the phone make sure your phone is muted. We are going to open up the phone lines then I'll ask for questions. And if you have a question unmute your phone and speak up. Okay, are the lines unmuted?

MR. FLESHMAN: They are now.

MR. LEAON: Okay. Do we have any questions on the telephone?

(No response)

MR. LEAON: No questions on the phone, okay. Any additional questions in the room for our panelists? All right. Well let's give our panelists a hand.

(Applause)

MR. LEAON: I want to thank you for volunteering your time. It was a very informative discussion. Thank you very much.

Let's take a break until three o'clock.

(Whereupon, a recess was taken off the record.)

MR. LEAON: Okay, we are going to reconvene the workshop. If everyone could take a seat we'll begin the open stakeholder comments portion of the workshop so we can get you out of here by four, or earlier. Everybody take a seat and let's get started.

Okay, this is the portion of the workshop, basically an open comment period for stakeholders. I think for this portion we can -- if you haven't spoken before go ahead and fill out the blue card. But if you have, or you filled out a blue card, you don't have to go through that stuff again but please identify yourself when you come up to the podium.

In the Notice for the workshop we asked that stakeholders focus on the question areas that were included in the attachment to the Notice and provide comments on those areas and feedback. So with that do we have anyone in the audience that would like to come up and speak?

It looks like you may be getting out of here soon. All right, we have one speaker. Come on up to the podium. And if you could provide your name and organization.

MS. LYNCH: Yes, I'm Mary Lynch with Constellation. And I just have some just very brief remarks. First I found today very interesting. Lots of really good information about the RPS and where feed-in tariffs might fit in. And was particularly intrigued by what I guess was referred to largely as the GAP analysis for the one to 20 megawatt units.

But in my comments I did want to just take a step back. Because as we read through the very good report that the CEC commissioned here it had the section on how this interplays with important Commission policies. And I am mainly referring to the CPUC here.

But I just wanted to take a step back and sort of remind all of us that there are a couple of very important Commission policies out there besides the RPS, which the report focused on in terms of interactions of feed-in tariffs. And those policies are a very strong commitment to competition.

And it seems to us that particularly with respect to facilities that are larger than the 20 megawatts. And I don't know if 20 megawatts is exactly the right number or not. But with respect to the bigger facilities, something like a feed-in tariff seems to us to be very much a command and control approach.

And at the end of the day it functions probably not much different than what we're using today with the utility RFOs, which are largely command and control to some extent in that they agree to pay a price for something that we all deem we want, regardless of whether or not the markets are supporting that investment.

So I think it is important to keep in mind as we evaluate something like a feed-in tariff to make sure that we have thought through very clearly whether it is consistent with that commitment to competition and the commitment that the Commission has had to increasing competition in the generation sector. Hopefully, according to their policies, moving as far forward as going back to a regime that supports merchant investment.

The other policy that the Commission has consistently reaffirmed its commitment to is the policy of customer choice. And in that regard it seems to us that feed-in tariffs, again particularly for large facilities, are not consistent with that policy because they lead to non-bypassable charges. And as we know it's one of the large reasons that direct access is not being reopened now is because of non-bypassable charges. And so I think we want to think long and hard before we implement mechanisms that are going to increase the existence of new, non-bypassable charges.

In that regard it also seems that the draft report suggests that we are considering feed-in tariffs largely because we don't have RECs. And I think this has come up somewhat in the discussion. That if we had RECs, and when we have RECs. It appears that we're hopefully moving in that direction, that something like a feed-in tariff hopefully would not be necessary in order to support investment in renewables.

That's something that RECs should be

able to do and it seems to us to be a much more market-based approach to supporting investment by allowing us to continue focusing on the Q rather than the P. And let the market determine what the most efficient resources are through something like a RECs market. Which of course seems to be very much more in line, at least in our thinking at this point, with a cap and trade regime for carbon.

In summary, it seems to us that markets work best to support investment through competition, but it requires very clear rules and a lot of regulatory certainty in order for investors to come to the table with investments that don't rely on regulatory backstop. So we suggest that this evaluation of feed-in tariffs keep those policies of competition and customer choice as much at the forefront as we do looking at how something like a feed-in tariff would or could or doesn't dovetail with an RPS program. Thank you.

MR. LEAON: Thank you very much for those comments. Do we have any other stakeholders in the room who would like to make comments?

Joe, do we have anyone on the WebEx?

MR. FLESHMAN: (Nodded).

MR. LEAON: No, no one on the WebEx, okay. No other questions in the room?

Let's try the telephones just to make sure.

MR. FLESHMAN: They are unmuted.

MR. LEAON: Is there anyone on the phone that would like to make a comment? If you can identify your name and organization.

No comments from the phone, okay. Once again, any comments in the room? All right, well.

ADVISOR TUTT: Mike, Mike. I wasn't going to make a comment as much as a closing comment if you are ready for that.

MR. LEAON: We are ready.

ADVISOR TUTT: I wanted to thank everybody for coming and to indicate my belief that I think that we are all after, everybody in the room and everybody looking at this issue is after the same basic goal. Which is, in my mind, achieving our renewable targets and policy goals at the lowest possible cost.

When we are looking at that we have set up a system of competition in California. What I think we are looking at now is to some degree the tradeoff between the benefits of competition. We all are aware of those. You know, you try to achieve or choose the lowest price contracts in your competition. So you're trying to get low-priced renewables in the ground and working for California.

And what I will call the costs of competition. This paper and other work around the globe has identified that there are some costs to competition in the form of risk that add overall to the cost of the procurement picture. There are some transaction costs to competition. We've talked a lot today about how for smaller sized renewables those transaction costs are a higher percentage of perhaps the burden than for larger sized renewables.

So that was the tradeoff I wanted everyone to keep in mind. What's the right balance between the cost of -- the benefits of competition and the cost of competition as we move into this may get -- it differs for different renewables. Maybe it differs for different sizes.

We are looking for written comments on all this in trying to understand what the policy direction should be moving forward. Thank you.

MR. LEAON: Okay, any other remarks from the dais?

CPUC ADVISOR ST. MARIE: Thank you, no.

MR. LEAON: All right. Well, unless there are any further comments this will conclude our workshop. I want to thank our presenters from the CPUC and from our KEMA contractors and also the panelists. Very informative information.

Our next workshop will be scheduled for September 3. I believe that one will actually be a Committee Workshop.

We will be taking the information today. The transcript of today's workshop will be available on the website and we will be taking your comments both oral today and written comments. Make sure you do your survey as well. We'll have that up and running as soon as possible, no later than Monday.

I appreciate your participation and we look forward to hearing from you and seeing you again at the next workshop. Thank you very much.

(Whereupon, at 3:20 p.m., the Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, 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 14th day of July, 2008.