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CALIFORNIA ENERGY COMMISSION

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Estimating Costs of California)
Generation Resources)

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MAY 16, 2011 9:03 A.M.

MR. ALVARADO: Well, good morning. We might as well get this workshop started a few minutes past nine. My name is Al Alvarado with the California Energy Commission. I am one of the team members involved in this effort to review and have a discussion about different cost consideration models with the intention of ultimately investigating to see where we can go from here.

Just before we start, we have a few housekeeping items. For those who are not familiar with this building, the closest restrooms are located just right across the hall. There is also a snack bar on the second floor under the white awning. And lastly, in the event of an emergency and the building is evacuated, please follow our employees to the appropriate exits. We will reconvene at Roosevelt Park, which is located diagonally across the street from this building. Please proceed calmly, quickly, and again following the employees with whom you are meeting to safely exit the building. Thank you.

With that, I see we have a full house here today, mostly those present right now are the folks that will each be giving a presentation. And we're also going to have several presenters that are actually going to be giving their overview of their tools remotely, too, later on today. With that, maybe I'll just kick off with Ivan Rhyne.

MR. RHYNE: All right, good morning. So, as Al mentioned, my name is Ivan Rhyne. I manage the Electricity Analysis Office here at the Energy Commission. And so, we're trying to have – I'm going to try and kick things off with a little bit of just kind of setting the stage for what it is we intend to discuss and, more importantly, what it is we intend to accomplish here today.

We've got quite a few folks in the room who have put in the time and the effort to develop estimates of costs for different purposes and using kind of different sets of assumptions and all of that, and we wanted to get those folks together on one side and we also wanted to have some end users in the room, as well, to have a discussion today about what we should be doing, how best to answer a question. And the question is relatively simple if you pose it this way -- you can put it many many ways -- but when you boil it right down, the question always comes down to, "What is the cost of building a new power plant in California?" And, to channel my inner economist, the answer is, of course, that “it depends.” It depends on a large number of things. It depends on assumptions, it depends on what you intend to use this for, and how you approach the problem in general can give you a completely different estimate of cost.

The Energy Commission has done a lot of work in this area in attempts to capture the costs and estimate those costs through one model, which Joel Klein will be presenting here in a little while. But we’re not the only ones in this space and we’re not the only ones who have had to tackle the issues and the challenges and the problems associated with this kind of modeling.

So, to get down to it and really answer this question is exceptionally difficult, and the folks who are in the room here can attest to that, it depends on what sources of cost data you choose. Well, there are variances of costs across time, across regions, and even for the same technologies in different points, and even within the same year there could be cost variances. You can choose different capacity factors, in other words, what choices you make about how this plant will operate over its lifetime can have a dramatic effect on what the overall cost ends up being. How do you capture financing costs? How do you capture the way these things are put forward in terms of, well, if the developer uses this much debt, or that much equity, how does that change the outcome? What to do about the inclusion and exclusion of system costs? This is a very important question because we typically have looked at cost modeling as simply trying to capture the cost of putting the resource in the ground, building it up and operating it over a lifetime, exclusive of these system costs, but that's not the only choice we could have made, and there are arguments for why we might want to make a different choice in the future. And we want to have that part of the discussion, as well.

And the last part, and certainly not the last, but the last one I want to highlight, is how do we handle cost trends, specifically there is a long running expectation that renewables cost will change over time, they are not a fully mature technology. And so, what is going to happen to, for example, solar costs over the next 10 or 15 years? If I build a solar plant today vs. if I build it five or six years from now, I may be looking at a very different state of technology with regard to what that's going to do. So, the manufacturing technology behind solar may have improved, there is a learning curve, there is a technological learning curve involved, how do you handle that? What assumptions should we make, can we make, about those types of things?

So today's workshop is meant to invoke Linus' Law and this is a software paradigm. If you've never heard of it, this is actually in reference to Linus Torvalds who, himself, never said this, but was actually inferred from the way that he works, which is, given enough eyeballs, all bugs are shallow. Well, we're hoping that we have enough eyeballs in the room, enough eyeballs online, and enough eyeballs who are members of the stakeholder community with regard to these cost estimates, that we can identify where there is room for improvement in how we do business and how we can identify best practices going forward.

So, today's workshop is meant to be a dialogue on strengths and weaknesses of different approaches. It's not just among developers, but it's also between developers and users, so we all at some point are both producers and consumers of some of these numbers. As some say, it's whether or not you're willing to eat your own dog food, right? It's, if you're going to produce these numbers, what do you do with them? How willing are you to stand behind them, those types of things.

And we're going to split this workshop into two halves, so the first half is how did specific models and modeling teams address the challenges of cost modeling in their products? And so that's where we're going to have these experts here at the front of the room come up and give presentations on the choices they made and why they made them behind the development of their specific models. And then, the second half of the day, we're going to draw on their expertise again, but we're going to shift the paradigm just a little bit and we're going to talk a little more broadly. What do these experts believe are the best practices in terms of cost modeling? This is information that's really important to us, going forward. And the reason it's important is because the CEC is going to use the feedback gained from this workshop and the stakeholder input to guide a really fundamental review of our cost modeling approach.

And so the questions in the agenda, and there are quite a few, if you don't have an agenda, it's available online or it's available at the front of the room, these questions are meant to be a start of the discussion rather than all inclusive. After each presentation, I would invite anyone who is a stakeholder, either online or if you are in the room, to either raise your hand online or come to the podium, and add to the discussion with regard to your questions, again, keeping in mind how we've kind of tried to split the day up. If you have questions that are specific to clarifying the choices specific modelers made, that would be the time to come up after each individual modeler. If you have questions about or comments about the larger approach, I would ask you to save those for the second half of the day when we hold the roundtable discussion on these issues.

So, the written comments are both encouraged and welcomed from model developers and end users, any interested party who has reason to pay attention to this kind of information. And finally, the written comments are due May 31st. There is an email address listed here where you can send it and you'll want to list the docket number, as well, to make sure that it's properly categorized and gets to all the right places internal to our organization. And so that's just meant to kind of set the stage, and we've got a lot of good information that will hopefully fill up the day and make for a productive discussion. A first part of that discussion will be from Mr. Joel Klein, he is the kind of chief architect for the California Energy Commission's cost of generation model, and he's going to kick us off this morning, so, Joel?

MR. KLEIN: Okay, good morning. Again, I'm Joel Klein. You may or may not have a copy of my presentation. If it wasn't there when you came in, it's now out there, I understand.

We all know that I could spend the day talking about my model, as any of you could, but we don’t have that much time, so it’s going to be sort of a quick overview and we’ll hope it’s enough – why don’t we – ah, that’s better. Okay, first of all, can everyone hear me? Okay. If I start mumbling, please raise your hand and complain.

Okay, there are basically two parts to my presentation. First of all, I’ll give you an overview of the process, the thing that the model is about, and then I will get into the model itself.

The basic reason why we have the model is to produce the biannual Cost of Generation Report. And the reason we have the Cost of Generation Report and the model, both, is to provide a single set of levelized costs and supporting data for studies at the Energy Commission. The goal is everybody is working with the same tools, the same data. Well, we’re not quite there yet, but we’re working on it. One of the problems, of course, is everything has to be in the right time sequence. Our data has to be available when it’s needed. Thirdly, a lot of people, a lot of entities, rely upon our data, or model, our levelized costs, and you see some of them up there.

Okay, when we went to develop this model, we had certain global objectives, and there they are, sort of like motherhood and apple pie, you know, produce a transparent, easy to use flexible model, great data, and great documentation. Okay, let's get more specific about the design objectives.

Okay, our very first objective was to have a large array of technologies in a single model. Before 2007, this was about, oh, a dozen or two, probably a couple dozen of individual spreadsheets, and we could see that wasn't going to work, so we wanted to get everything into one module; if you don't have that, it's hard to keep things consistent, underlying assumptions consistent, it's hard even to keep track of what version you're working on. We decided that we would accommodate all three types of developers, and a lot of these models just preoccupy themselves with cash flow accounting, we wanted to also be able to do IOU and POU accounting, so Revenue requirement accounting. We wanted to have multiple years to capture changing costs – Ivan just referenced that. And on the next slide, I'll demonstrate that for you a bit. And we wanted to be able to measure levelized costs at each point of measurement, at the busbar of the plant, the high side of the transformer, and the delivery point downstream where the power is delivered.

Okay, now if you look at this curve, you can see, for instance, that there is solar PV just dropping like a rock. If you're just going to look back here at 2009, like our report does, it's a very poor representation of how that technology is competing in the oncoming years. So, we see solar PV and solar thermal dropping very rapidly. We see wind coming down pretty well, and geothermal. The rest of them, at least according to our assumptions, are relatively flat. This is a little learning curve, it's a little development there, but not much. And these are in real dollars, so this is the real trend in the costs.

Okay, some other design objectives. We wanted to have levelized cost by geographical region, that is, to be able to use fuel cost by utilities, air and water by basin, particularly for the ERCs which, for instance, in South Coast, can be very high. Of course, if anyone knew what those were, that would be nice. But, anyway, that's – still struggling with that. We wanted to have a model that could enter capital costs either as instant costs or installed costs; a lot of these models will take costs as installed costs, but they won't calculate the installed costs if you're starting with the instant costs, and we wanted to have both. We wanted to be able to calculate the GHG adders and their costs, we have that in the model, but we don't have that in the data in the models, so it really hasn't been used yet. The mechanism is there. We have high, mid, and low cost. And I'm going to be coming back to that more than once. There is no average cost. All the time, it asks for this cost, well, there is no average cost, there are a whole bunch of ranges of cost, so to try to fight that delusion, we have a high, mid, and low levelized cost, which means, of course, you have to have high, mid, and low data, cost data, and performance – planned performance characteristics, same thing.

Okay, another thing we're concerned with is that, yes, those tax credits are out there, but not everyone can successfully take care of them all, cannot utilize them, so we wanted to have a mechanism to say, "Okay, what would it be if maybe you're not quite so successful in being able to utilize the full tax credit?" Maybe you can't use it all in the first year, for instance. Now, this shows our input selection window in the model. If you look at the plant type selections and you click on here, you have one of those dropdown menus, Eric Cutter developed this for us, and he made the first cut at the model, so he certainly knows what I'm talking about. In this case, we've selected wind, class 5, you choose the type of financial ownership for wind, we have emergent alternatives, again, it’s a dropdown window you select. These windows – this window here is sort of the fault of that, just try to ignore that for now. General Assumptions is a bunch of things like State and Federal taxes, and transformer losses, data regarding the tax benefits, it’s sort of a hodgepodge of stuff, but nothing I want to dwell on. This just reflects, once you’ve selected this data, like this Wind Class 5, this tells you that the data is in 2009 dollars, wind is the field type, and the KEMA – this was the source of the data. And we’ll get on with that, a little bit about the data, a little later on.

Okay, here is where you select the start year and you enter the day it ends, so for this plant, it would be for a plant that was going in service in 2011, this year, gas prices are average, air and water costs are average, that is statewide, that’s what we mean, and average, nominal, most common price. The study perspective selected here, this is another dropdown menu, is at the busbar plant site. This shows that the data was entered as instant as opposed to installed costs. This is just something that supplies the combined cycles if you have – like a basic configuration has two CTs; if your particular combined cycle unit has more than two, you can select three, four, five, whatever, and it makes incremental adjustments to the instant cost, it's sort of a convenience because there's a lot of combined cycle calculation going on. For this one, we have no carbon price, no data, no carbon price. The scenario is the mid-range, the middle one, the so-called nominal, average, whatever you want to call it, whatever that is. And loss covered in a single year means that you have the most favorable success with your tax treatment, okay? Everything works fine.

Okay, here are some other design criteria. We wanted the ability to create, save, and recall scenarios. We have set scenarios in there, but what if you didn't like our heat rate for a combined cycle unit, and you wanted to put your own in? You can do that, and then you can save it as a scenario, recall it later should you need it, without disturbing the base data that is in the model. We elected to have fuel costs by year, a lot of these models just have initial fuel costs and then an escalator. We think fuel costs can be so erratic, we thought that was too simplistic. We wanted to include plant transformer and transmission losses. We wanted to include capacity and heat rate degradation. We wanted to account for start-up costs. And we also wanted to have a combined cycle heat rate that was the function of the capacity factor. So, when you set the capacity factor in the model, it gives you the heat rate that corresponds to that capacity factor. Now, that's just for the combined cycle unit only.

Okay, here are outputs. This may seem like an unnecessary subject, but it was a big challenge for us, part of it, because no matter what format you have to your data, somebody wants something else, so we tried to provide a complete array of formats and we found that there was a lot of work associated with that because we have a lot of technologies in the model. Depending on what year you're looking at, it's anywhere from about 21 to 25.

Okay, we wanted upfront where people could see it, we wanted levelized and annual costs, we wanted dollars per kilowatt year, dollars per megawatt hour, and cents per kilowatt hour, anything people might ask for. No matter what you give them, they seem to be asking for something else. We wanted to provide the fixed and variable component levelized costs. So, if you want to compare the costs of F&M cost in one model, leveled fixed O&M in one model to another, it would be right there, you could see it. And I often want to do that sort of thing, so that's nice. As I mentioned before, we have mid, high and low input data, and the corresponding levelized cost. Now, amidst all this, something became somewhat of a challenge is, all of a sudden I realized, well, we've got, let's say, 21 technologies. If you run those one at a time for all the combinations we want, we've got three types of developers, you've got two years that you're doing, before you know it, you've got 378 separate runs you're making to fill out the sheet, and then you've got to transpose all the data. That turns out to be about 12,000 pieces of data to deal with. So we developed a series of macros so we could print our data. And you know how it happens, just as you get to the end of all these calculations, you realize you've done something wrong in the model, and then you start from the beginning. So we definitely thought we needed that macro. Here is what our output looks at in the model, this doesn't show the cents per kilowatt hour, but all the other outputs do. So you can quickly look in our model and see each component, and that's helpful. And this is truncated on the end, but this shows the annual cost. We find this graph is useful because sometimes, if you've done something strange in the model, you see a strange little kink in one of those lines. And not all the developers have such nice smooth lines, all the technologies.

Here is an example of an output we have. And notice there are 21 technologies. You’ve got all those components to the data. Now, that’s just the dollars per megawatt hour. You’ve got dollars per kilowatt year, you’ve got the three developers, you’ve got two years, so you want to be able to – we found that was essential for us. Whereas a lot of you may be looking at individual technologies and working with clients, let’s say, we’re trying to provide planning data, so we’ve got to provide these masses of data. So maybe we’re somewhat unique in that regard. And the same thing for the input data. You’ve got the plant characteristics and the plant cost data. And, again, that’s just average, you’ve got average, you know, high, low. So maybe I’ve dwelled on that a little bit, but that’s a challenge that we face.

Okay, another challenge we face is people are constantly trying to misuse the data, as I’ve alluded to before. The worst thing is this one-size-fits-all, they want this number, “A combined cycle unit costs this much.” Well, as I mentioned, don’t believe that for a second, so that’s why we have the high, low range.

As Ivan mentioned earlier, probably the most common error is ignoring the effective capacity factor, so we've provided screening curves in the model and I'll show you how that works. Again, we're trying to sensitize people to the fact that you can't use one number and try to use the right data for the right job.

Another point I want to emphasize, and it's a common misunderstanding, is levelized costs are just the costs of building the system, building the unit, they don't tell you anything about how it affects the system, or how the system affects the unit. Electric capacity factor, we mentioned. You build a CC, you assume it's going to run at 75 percent capacity factor, you get in the system, and you find out you're running at a 40 percent capacity factor. So that's why we developed that screening sort of mechanism and I'll show you that in a second. Another common confusion is people want to know why some price they see doesn't equal my cost, well, they're not the same thing for a whole bunch of reasons and we could probably spend a half an hour discussing that. But one of the common things is often they have other sources of revenue. Again, their particular cost may be high, low, medium, whatever, there's a whole bunch of reasons.

Well, here we've got the costs, here's what we've got, let me expand that a little bit and I'll show you. Now, you want to sort of ignore the two hydro things because the physical configurations of where you develop hydro are so – have such a wide range of physical differences that maybe that's a little misleading. And you can ignore the simple cycle units because they're for specific purpose and, in this case, they show a five percent capacity factor. So they don't really fit in here. So if you look at these costs here, you get to maybe where you get to solar, it depends a lot on what your cost is, you know, if you take this medium cost and you say, "Oh, this one is going to be cheaper than this one," no, your cost may not be that because you've got to consider the high low cost, so you would have to have a handle on your cost. You cannot make the simplistic comparisons.

Now, I'll mention, this is a little unfair to solar, I picked 2009 and, I showed you earlier, solar is dropping like a rock. If you went out a few years here, you see that it's much more competitive, and we've all seen bids that suggest that it's much more competitive. We've seen bids in Nevada for $150.00. Of course, they don't have our cost, but….

Okay, here is screening curves that I was talking about, the mechanism. This shows the old one we're familiar with, of an advanced combustion turbine against a combined cycle unit. Notice these cross, an interesting thing, one of the problems we had, if you take an "F" type combustion turbine, they don't cross, and that's been the subject of a lot of consternation for a lot of us. But this is going to be the more common technology that's out there now, and so we can revert back to where we actually see those lines cross. Probably the reason why they don't cross is we don't – if we'd used "F" type turbines, I think you'd see them crossing, like I just said a moment ago, but we use these arrow derivatives, LM 3000's, and they're just a bit more expensive and you don't see that.

Oh, here is another thing, we have a sensitivity curve that's in the model. We want to see what drives your levelized costs the most, that shows you. For instance, capacity factor, okay, this one – let me back up – this is combustion turbine 100 megawatts, and as I mentioned, capacity factor drives, and so that is the one that drives it the most. You see installed costs for a percent change, and maybe I should back up a little bit, this shows if you increase the cost 10 percent, and you come up here, you see what it does to the levelized cost change. I sort of glossed over that, I don't know if I confused people or not, I apologize if I did. But, anyway, that's the purpose of having this mechanism in the model, so people can start to get the feeling for what really affects cost.

Okay, let's bomb on to data. We've talked about the model, things we've done in the model. This just shows you the wide range of data that goes into the model, and if you've done any modeling, you've seen all that before. Let me tell you where we got our data. We were hell bent to try to get quality data, so the first time we went around, I was not around, that was the 2003 IEPR, but I was part of the 2007 IEPR, and we went out and tried to get the best consultants we could, and for the renewables, nuclear, and IGC coal, that was NCI 2007. Later in the 2009 IEPR, that was KEMA. For the gas-fired units, we had Aspen do the work. And that's Richard McCann sitting over there, who ran that show, there were a number of people involved, but he was the Project Manager. In 2007, we got actual survey of the data. We sent out request forms, had them filled out, guaranteed confidentiality on the individual pieces of data, but we think that is some of the best data you could ever hope to get. In 2009, we only had a couple new units, so rather than going through the survey process again, we decided to compare our survey data against everybody else's data that was available, so we went through that comparison. At the same time, we made some adjusted costs for unusual real inflation that we knew was going on at that time. When the 2007 effort was going on, we knew by the end of it that prices were increasing so quickly for gas-fired units that our numbers were probably a little low, but by that time, it was too late to change them. But, for the 2009, we tried to capture that. So that’s the main two things that happened there. So at that time, we looked at individual data, we looked at every bit of data we could find, we agonized ad infinitum. I tend to think this data is pretty good. I’ve had other opportunities to confirm that it’s pretty good.

Okay, the financial variables were done by Aspen using BOE data, and E3 is going to speak to that subject this morning, right, Michele? Okay, and that will be a topic today, the first of the day to deal with, see if we can make some headway.

Okay, another big challenge is tax benefits in the model. For us, they’re all Federal. There were no data at that time, since then, that we understand is just State tax benefit, and I’ll get to that in a second. Okay, accelerated depreciation, that’s something that’s been around for a while. Most all these things are on accelerated depreciation for five years, and it makes a big impact on the cost, that is all the renewables. There is a TDMA, a Tax Deduction for Manufacturing Activities, most of the models I'm looking at don't seem to be dealing with this, and I'm not sure whether it's because it's very small, or they've overlooked it, or what. That's something we might want to mention to come up with, we might discuss today. Is the property tax exemption for solar systems? I think everyone is aware of that and that's in all the models. There's a geothermal depletion allowance. There is a renewable electricity Production Tax Credit, PTCs, a short acronym for that, and Business Energy Investment Tax Credit, ITC, and then there's the ARRA, American Recovery and Reinvestment Act. GDA, I think, applied to everything but solar – no, excuse me – PTC applied to everything but solar, and ITC just applied to solar, biomass, and what was it, Richard? Do you remember? Okay. But, anyway, along came ARRA, and this is something that we've captured I'm not seeing it in the other models yet, is ARRA backs up anyone who had PTC to allow them to have ITC, so if you look on our model, all the renewables have ITC. And furthermore, it allows them to expense everything the first year, one year, so if you look in our model you'll see that we have all those tax credits coming right in the first year, except for the case where we assume, as I mentioned before, we assume that life did not go so well for these things in the high cost case, where it just didn't work out, you couldn't realize them for one reason or another.

Okay, I will just mention up front, there are two -- Richard McCann was pointing this out to me -- there are two new tax benefits that came available since we've done our models, so they're not in the model. There's a sales tax exemption and there's 2010 legislation for 100 percent depreciation, so those aren't in our model, but if there's something, I guess it will be the next go-round.

Okay, finally, documentation. I look at so many models where I can't tell where they got the data or anything, so we decided, within our model, we were going to try and have really good data, so what we did is, in Excel comments, most commonly it's in the Excel comments, you'll see where we got the data or if there is subtle computational things, there are references in the data. So we tried to track everything we did that's within the model. Also, there are some instructional material in the model, there is an instruction sheet and whatnot, we tried to help people use the model. But there's a User Guide, and the User Guide describes the model, worksheet by worksheet, delineates, explains the subtle algorithms, how we did them. It has a chapter on instructions and how to use the model. And the model is pretty intuitive, but for those that have any reservations, it's there. And I have an Appendix of Definition, I have 23 pages of definitions because I think that's part of the struggle here is to see some acronym or some definitional thing and try to wonder what it is. If any of you look to the User's Guides and you see a little flaw or something you can help us to fix, we would appreciate that feedback, too. But, anyway, that's a brief overview, and if people were raising their hands and I didn't see it, I apologize, but do you have any questions at this time?

MR. RHYNE: Okay, so thank you, Joel. So at this point, I'm going to invite folks who are in the room who have questions, either from the panel, or in the audience, to one at a time share your questions and, Joel, if you want to go ahead and try to field those.

MR. KLEIN: Well, there's one or two possibilities. I don't like to think about one of them. Yes, sir.

MR. RHYNE: So, Joel, one of the questions that I wanted to make sure got addressed specifically, what uses would you recommend not using this cost of generation model for? What would you specifically steer end users away from using it? When would you do that?

MR. KLEIN: Well, one of the things to be careful about is it is based on California data. Now, you can override the data, and you can fix that problem. Another danger, as I previously mentioned, is looking in there and running that generic case and thinking you had the answer. Again, you can get in there and change the data and you can make this model, I think, work about as well as any model, and maybe we'll decide there is a little something there that can be made a little better, but it's designed to accommodate that. Okay? Edison, I think.

MR. SILSBEE: It's Carl Silsbee from Edison. Just a process question that maybe you or one of your colleagues can –

MR. KLEIN: I don't think your microphone is on, is it?

MR. SILSBEE: Okay, let's try again. Is it on now?

MR. RHYNE: Yeah.

MR. SILSBEE: Okay, thank you. Carl Silsbee from Edison. It's a process question for you, Joel, or perhaps one of your colleagues. I'm assuming that the CEC is going to update the cost of generation model in this IEPR cycle, so there will be a 2011 cost of generation report, as well?

MR. KLEIN: Not quite. Ivan, you seem like you want to answer that.

MR. RHYNE: Yeah, so to answer your question -- this is Ivan Rhyne -- to answer your question, we’re not planning on updating as part of the 2011 IEPR. We intend to use the 2011 IEPR process to conduct this kind of review and get this feedback, and we’re really considering moving this to a-IEPR year update schedule so that the updates would then kind of feed a little more naturally into the types of questions and policy issues that were raised during IEPR. So, for example, there are no decisions made yet, but for example if it were to work that way, we would do the update in 2012 and then those cost estimates would be available for use in our Policy Reports in 2013.

MR. KLEIN: Was that it? Is that everything, Carl? Okay. Anybody else?

MR. RHYNE: Was there anybody online who had questions?

MR. KLEIN: No questions online.

MR. RHYNE: Okay.

MR. KLEIN: It was either perfect, or I left them in oblivion someplace.

MR. RHYNE: Okay, so thank you very much, Joel.

MR. KLEIN: Should I introduce the next person after me?

MR. RHYNE: If you would, please.

MR. KLEIN: Okay. Next up is Ryan Pletka from Black and Veatch. We used their model in – they did some work for us in RETI and Ryan will talk about that in just a second, and he had the most trim model I've ever seen, it's all on one sheet of paper, he actually printed it out in one sheet of paper. If you've seen mine, it goes on and on and on and on, so, with that, I'll let Ryan take over.

MR. PLETKA: Thanks, Joel. Good morning, everybody. Again, my name is Ryan Pletka with Black & Veatch down in San Francisco. I appreciate the opportunity to be here this morning and speak with you about what I think is an interesting topic, we certainly – I don't know if we debate it quite as much as it sounds like it is debated here, but I think, just to set the stage, one of the very nice things in terms of developing this cost of generation for RETI, which is the Renewable Energy Transmission Initiative, is we have a very focused, clear application in mind, and a clear set of end users which was, in fact, just an internal model at the time, so whereas I think Joel's model has to be all things to all people, to a certain extent, ours didn't. We were able to just kind of trim things down and focus on what we thought was essential for the issue we had, or the problem we were trying to solve.

I’m going to give a little bit of overview of the kind of activities we do within the Energy Economics Field at B&V, just to give you a sense for where this model fits within the realm of other things. The model does have some nice things, and there is also a lot of, I don’t know, just warnings, I guess, in terms of its use. So I’m going to then talk about, in particular, the history of it, its features, pros and cons, and how it might be used. And then there’s something that we provide called GenCost, which might be of interest to people here, it’s actually a twice a year update on cost of generation as a subscription service, it’s a little bit of an advertisement, I guess.

So, the kind of things that we do in energy economics where the cost of generation model fits in, at least in the kind of broad high level studies that we’ve done such as Renewable Energy Transmission Initiative, or RETI, Western Renewable Energy Zones, which are called WREZ, and other things like that, that might look at, you know, State level or western-wide types of competing, if you will, energy resource options. We also do kind of three other broad categories of economic assessments. We do a lot of market modeling, which includes gas price forecasts, electricity price forecasts, locational marginal pricing type runs. Another thing we do which feeds into cost of generation is cost estimates for new generation technologies. These can be done at the feasibility level, but also, my company builds a lot of power plants, we build lots of combined cycles, we build coal plants, build solar projects, everything. So we do those cost estimates for those projects as part of our EPC or Engineer Procure Construct Activity. And then, finally, another thing that we do is a lot of financial due diligence, so reviewing cost models, pro formas put together for actual project finance, and mergers and acquisitions of companies and the like. And so, I mention that because I think it’s useful to kind of think about the granularity of the RETI cost of generation model vs. what we might do in a project due diligence.

And this was for a biomass project I worked on a couple years ago where there actually were 100 fuel contracts and the price of those different contracts might have been indexed to up to three different things, including diesel prices for transportation, labor cost, producer price index, and then, in some cases, those were broken down into monthly accounting. So, if you just look at that, you’ve got a huge amount of inputs just on fuel price, and that’s one component. So these models can be pretty large, you know, multi-megabyte models, if you ever printed them out, I don’t know that people do, but it could be hundreds of pages. Contrast that with the RETI cost of generation model where we have one of these ultra-simple fuel cost, $10.00 a million Btu and it escalates at 2.5 percent forever. So, the RETI model is really simple when it comes to these types of inputs.

Okay, so if people aren’t familiar with RETI, I think it’s useful to understand what it is, or what it was, and kind of the framework that we were working with when we developed a cost model for that. So, RETI was a statewide process, the whole intent of which was to identify kind of what are the next big transmission upgrades that might be needed, how do we evaluate and prioritize those? At the time RETI started, I think in 2008, maybe 2007, you know, we had the law for 20 percent renewables by 2010 and a 33 percent goal by 2020, and everybody was kind of trending towards we need more transmission to solve our way out of this problem, it’s the only way we’re going to be able to get to 33 percent, and our traditional framework for identifying and promoting those transmission facilities was not working, so RETI was established as sort of a – well, not sort of, but very much – a stakeholder collaborative process to think through those challenging issues. It was, you know, I think it brought together a great group of people led by the people here at the Energy Commission, Public Utilities Commission, and others, and the stakeholder ranged from everybody from the Sierra Club up to generation developers to utilities, the military, and the like. So, lots of different interests, lots of different levels of sophistication, if you will, as it comes to, you know, their backgrounds in energy economics. Here, on the Energy Commission's webpage at /RETI, there's all kinds of documentation, it's overwhelming, really.

So, RETI, just so you know, is currently – I guess the best way to say it is maybe on hiatus while other planning efforts in California go forward, but this cost of generation model lives on.

Prior to developing a cost of generation model for RETI, within B&V we had – we still do have – quite a few different types of cost of generation models, so when we were thinking about how we were going to evaluate the economics of these different resources, we thought about using some of those, but really kind of scrapped them all and came up with something fresh. And one of the things that we really needed to do was try to focus on what are the major factors amongst the different renewable technologies that differentiate them when it comes to the economics, and we had to have a model that kind of reflected the – I don't want to say, like, there's not one way to model anything, or one correct way, but the most predominant, most recognized sort of project structures, and so what that really meant was that we based it on kind of an IPP, a developer kind of merchant generator view of the world, since that's what most of the generation was looking at. So that translated into a pro forma kind of cash flow accounting approach, the calculation.

So back in 2008, we developed the first RETI cost of generation model and we put it out there for all the stakeholders to review and provide comments on. It was adequate, it was sufficient for the intended use at the time. So that was used for Phase 1A and 1B of RETI. It was then adapted for the Western Renewable Energy Zones Project, which essentially was like RETI, except it looked at the rest of the west, that process is still going on. So there was another round of stakeholder review for that. And then, finally, in 2009-2010, at this point, the ARRA Stimulus Package had passed and we needed to update that cost of generation model to take into account some of those new benefits, added some things that we thought were critically missing before like degradation and reflect new changes in the cost of the inputs for capital cost. So, right now, it hasn't been changed, at least since it's public form, it is out there still on the RETI website.

One thing I wanted to point out that is a key point, I guess, that should be a take home for everybody is that – and I think this was made by the other presenters, as well, is that the cost of generation is really in and of itself not the one way that you should look at the economics of resources. There are many other things besides cost that need to be taken into account. So, in RETI, we distilled that down to five things and we developed an algorithm, it's pretty simple, just to rank resources against each other. So we have a simple equation, we call this Rank Cost, and it's equal to the cost minus the value. The cost includes generation cost, or the cost of generation, transmission costs, and a little adder for integration costs, and then on the value side, we calculated energy value and capacity value. So, the cost of generation model I'm talking about today really only focuses on this generation cost term, but just bear in mind that, within the RETI framework, and also within the Western Renewable Energy Zones Project, there's sort of a larger equation, that this is one component of.

So, a brief overview, again, it’s a simple pro form cash model used to determine cost of generation. It is based on Microsoft Excel, as I’m sure every model practically is. And we were essentially trying to make a model that would allow different projects to be compared on a relative basis, really, the output of this model is just the levelized cost of energy. I mean, you could use – you could derive something from the other things that are on the Excel spreadsheet, but the single output we’re interested in for the purpose of this is just levelized cost in energy, and it does include incentives and I’ll talk a little bit more about that in just a minute.

So, some of the key features of the model is that it’s simple, it’s simple, and it’s simple, and that’s about it! But let me talk about why it’s so simple. Because we had, you know, everybody from the Sierra Club and the Military looking at this model, we needed to really have a model that people could look at and hone in on the major kind of cost drivers, the levers, if you will, to sort of favor one thing over the other, and it had to be applicable to all different types of technologies. We don’t have different models for different technologies of one common model, you just plug in different inputs. And we also needed to model projects in Mexico, Canada, and the U.S., so instead of making a structure for each of those, we tried to make our inputs as flexible as possible to accommodate those kinds of things. Then, the last kind of three elements that are on the slide here that, within RETI and Western REZ, there's a lot of different projects that we're modeling, RETI has like, I think, 1,200 or so, and we have a lot of different scenarios that we model, as well. So, we needed to have a limited number of arguments. We developed a way to make it a non-iterative model, it's a linear model, so we're able to solve without using a solver, which if you've ever used that, it can make things a lot more difficult, and it had to be a very quick model.

This little chart down here just shows a little snippet of some of the RETI work. And each of these cells here is one cost of generation calculation, and we've got different incentive kind of frameworks, IPP developer with investment tax credit, production tax credit, prior to Mexico, Canada, so when you have seven different scenarios, or six different scenarios, plus 1,200 projects that results in thousands of calculations, and this model runs over and over again in different broader context scenarios. So, really, it's able to churn through all this stuff really quickly because it’s so simple.

Here is just a little screen shot of the model. I don’t expect you to be able to actually read any of this stuff, of this resolution, but as was mentioned in a very straightforward one-page type model, and just to look at what some of the inputs are, there are about 30 inputs to this, you know, basic stuff like what’s the capital cost for the project, fixed O&M, variable O&M, and you’re allowed to escalate those things at whatever rate you deem appropriate. And then there are some capacity factor and heat rate. We certainly don’t have all the complexity that is in the CEC’s cost of generation model, it’s a much more simple model and, by the way, part of the reason for that was that we’re just modeling – it was just intended to model renewables, not necessarily natural gas projects. So that was one reason why. And then, a variety of different financial inputs, as well, you know, your debt to equity ratio, debt term, different types of accelerated depreciation, and then, in terms of incentives, it can model production tax credit and investment tax credit, and you could also model the grant, essentially very similar to the investment tax credit. So that’s it for the inputs, really pretty straightforward, and many of those, like the financial assumptions, would be common for a lot of different types of applications.

So then there's a very simple cash flow statement below the model inputs that, you know, calculates the revenue, the operating expenses, applies debt service, and then calculates taxes, and then from that you get an after-tax cash flow that's used to calculate the Internal Rate of Return for balancing the model. There's sort of a trick that's in this model that we use to avoid the iterative calculation that a lot of times you get when you're trying to solve for IRR, and because the model is so simple, it allows it to – essentially there is a linear relationship between the first year of cost of energy and the net present value, and the only reason I'm bringing this up is because the most common question we get on this model is people don't understand, there's a little part of it that's got the use of the table function, which I think is used very rarely by a lot of modelers, but it essentially allows you to do kind of what if, or scenario analysis, with the model. And what we use is we use that to make two runs of the model to generate two data points and from which you can calculate an equation for a line, and that line is then used to tell you what your first year cost of energy needs to be in order to get to a net present value of zero. So, based on that, we're able to solve without having to do any iteration, which really helps speed the calculation and makes things a lot more robust in terms of not crashing, for example.

Okay, so kind of in summary, in terms of the pros, the model is simple, it's not iterative, it's fast, it's been through a few rounds of stakeholder review now at this process, and it's certainly not the most accurate model in the world, but somewhat accepted, at least for these purposes. And it's generalized so long as you can put things within the framework of a capital cost, the capacity factor, and O&M cost, you can model just about anything you want. And, you know, I think it's a good model for screening and to have relative comparison of different project options. That said, you know, we really designed this model just for our use at Black & Veatch, and so the nice thing about these other models that are out there is they are meant for other people to use them, and that wasn't really the case with our model. Now, it has been used by other people, and so we do get a lot of questions on, well, what about this, what about that, and you know, that was never our intent, so we've never really documented the model. This is probably the most it's ever been discussed in a public forum, so -- besides the RETI work groups and things like that that reviewed it. There are so few input assumptions that, you know, people are looking, where do I put in property taxes? Where do I put in my state tax rate? Where do I put in this and that? And there's not input assumptions for that. You've got to essentially combine everything and force fit it into the line items that are there; for example, you know, Emission Reduction Credits or those types of things, those need to either go into the capital cost or the O&M cost, depending on if you're talking about upfront or ongoing cost.

Also, it's a real simple approach to timing issues, there's no actual years anywhere in the model, like this is a 2010-2011, none of that is taken into account. And there's no real provision to have capital cost declines over time because, within RETI and REZ, that was sort of within the framework of those two projects, it was determined that we weren't going to assume any kind of capital cost declines, so we didn't build it into the model. And definitely, this is not the type of model you would use for project finance, at least I hope not.

So, I'll give you a feel for some different types of example applications that RETI has been used for, these are from RETI and some other similar type projects. And I think a real good benefit is, because it is so simple and so straightforward, you can run it lots and lots of times and look at lots of different scenarios. So, one of the things, and this is kind of interesting on the historical side, is that when we looked at the cost of generation for different renewable technologies in RETI Phase 1, that's what this chart is supposed to show, so this is levelized cost a generation going from zero to about $300 a megawatt hour. These are the different renewable technologies, biomass, wind, geothermal, PV, thin-film tracking, and then solar thermal -- 2008 seems like a really long time ago now in terms of generation costs. So, this is just the range of costs for technologies at that time that we had in RETI. This was before the latest round of new incentives and subsidies. And one of the big reasons that all this information was updated for Phase 2 of RETI was that there was a big change in some of these cost ranges. So the darker green bars represent the estimated cost of generation that was used in Phase 2 of RETI, and also pretty similar for the REZ project. So you can see here in light green was a PV cost, there is a dramatic drop that is reflected in the modeling of about $100 a megawatt hour and, also, similarly for thin-film, it was really only a sensitivity study back in 2008 because technology wasn't deemed to be fully commercial, whereas in 2010 it was. And then there was some other shifting in the other technologies. Generally, there was a lot of benefit from the Investment Tax Credit being available to all the technologies, which was realized in these darker green lower costs for biomass, wind, and geothermal, as well. So that's one type of thing, this kind of very characteristic floating bar chart for economics.

Another thing that it has been used a lot for is to develop supply curves, different resource options. So, in this chart along the bottom axis, it's generation potential, this is in Terawatt hours per year. And the different colors represent different renewable resources, the kind of reddish being geothermal, yellow, solar, wind, and purple, green is biomass, and blue is hydro. And these are stacked up from left to right in order of increasing cost. And this is again kind of a rank cost metric, this is adjusted delivered cost of energy with a value component in it. And this is actually from a current kind of task force with helping out within San Francisco, looking to see if the City can get to 100 percent of its energy supply and release electricity from renewable resources. So, in the case of San Francisco, the dash line represents the total demand in 2020 in San Francisco and theoretically everything to the left of that dash line on that supply curve would be the most economic resources. Again, a good thing to point out, I think, that Joel pointed out, is this is a cost model, not a price model, so it doesn't mean you're necessarily going to be able to get these things for those costs, but it allows you to sort of prioritize. And so the cost of generation model, what it does, is each of these points, or each of these bars on this is one run of that cost of generation model. This is a similar curve, this is from the RETI work from the Phase 2B, again, another supply curve, similar type comparison generation on the bottom axis, and a weighted average, ranked cost, and I don't necessarily expect you to be able to read these things, but these are the Zones that were identified in the RETI Phase 2B, or, actually, RETI Phase 1 process. And the average cost of generation from the average rank cost from each of those Zones. So, way over here on the left of the lowest cost resources are the Solano Wind Resources in Palm Springs, and the most expensive resources are British Columbia – it doesn't matter what it is, but it's the most expensive, it's hydro, wind, and geothermal and biomass. The dark green line represents the average and then, on each of these, there is an uncertainty band which represents the expected variation in the resources available from those Zones, based on what we feel is the kind of uncertainty related to key model inputs associated with capital cost capacity factor, etc.

And then one of the other kind of things we do, because the model is so quick to run, it makes a good model used for Monte Carlo type simulations where you're looking at lots of different types of scenarios, and in this case, we were doing some studies on the cost of capital and how that affects PV system cost of generation. So, each of the little points, again, is a little run of this model and we don't need to talk about what the chart really shows, but it allows you to run thousands and thousands of different cases, really, in a matter of a few seconds, so it is good for that kind of thing.

Okay, the last thing I want to talk about is something that might be of interest to somebody, is this thing we have called Gen Costs. And you know, it kind of strikes me as odd that this is something, you know, cost of generation from different resources is something that should be much more easy to access and to find reputable sources and to go to like the EIA and hope that they might have something, but, you know, you could look at the EIA, you could look at NREL, you could look at five different Federal Government sources and get five different answers for costs of generation. And also, the timing of this stuff, even something from last year at this point is a little bit questionable for what power costs.

We have something called the *Energy Market Perspective*, which is a market modeling forecasting type product and, within that, there's a set of inputs that we need to develop every six months anyways for capital costs, operating costs, and everything else, that goes into the cost of generation. So, we have these inputs available and we're making these available now as a separately sort of published part of this *Energy Market Perspective* and, because it's every six months, it's going to have a real fresh nature to it, we think, and sort of capture the dynamic of changing costs and PV or natural gas price forecasts, things that really have sort of quick changes in those characteristics. So, this is some of the assumptions from the last go-round of this product offering, so we got a lot of different generation technologies. We're looking at biomass, coal, nuclear, I guess all the usual suspects, and then, you know, range and capacity factors, a range of capital cost estimates, and that of course gives you a range of cost to generation. So, just some different values from that table and, then, that you can then graph and make again one of these floating bar charts. So here's just a comparison of kind of our view, or at least our view as of 2010, of what the comparative economics are for the different generating options, you know, wind down from $50, from the low end, up to $100 a megawatt hour, and in comparison, gas combined cycle around $100 a megawatt hour. So, obviously, there are a lot more assumptions that go into this that I'm not going to get into right at the moment, but just the ideas that we'll be publishing this stuff on an every six-month basis, the next round will probably come out this summer. And we're also, of course, tracking this over time and to see how things change over time. Yeah.

MR. KLEIN: What dollars are those?

MR. PLETKA: 2010 dollars.

MR. KLEIN: Thank you.

MR. PLETKA: Thank you.

MR. KLEIN: That was Joel Klein.

MR. PLETKA: So with that, that's all I had for prepared remarks.

MR. RHYNE: So thank you very much, Ryan. I've got a couple of questions, but first I want to open it to the audience. Any questions for Ryan? No? Okay.

MR. KLEIN: I’ve got one question. When you were doing the RETI work – this is Joel Klein – when you were doing the RETI work, did you run production cost modeling? I couldn’t quite capture that. I mean, how did you – you actually were doing some production cost runs?

MR. PLETKA: Not as part of the – yes and no. So, in order to do the valuation, the energy value and capacity value, there was a production cost model run to get like a 20-year forecast of what the value of energy is in California, and that was based on, I think, the 2007 scenarios project, or something like that that some colleagues of mine did for CEC. I’m not sure exactly of the year, but RETI didn’t then do any kind of simulation of a build-out of renewables in transmission with its own production cost model.

MR. KLEIN: Okay, I’ll add one comment regarding your table function.

MR. PLETKA: Uh huh.

MR. KLEIN: After I got through criticizing and talking about how I didn’t like it, we ultimately decided to use at least a perturbation of that, so thank you.

MR. RHYNE: Good. Al.

MR. ALVARADO: This is Al Alvarado. Ryan, thanks for joining us today. You presented a slide where you showed your updated capital costs and I was wondering if you could talk about the source of your information for updating some of those generation cost estimates.

MR. PLETKA: Yeah. I guess there are kind of three general sources. The first is kind of internal, Black and Veatch numbers, and by that I mean – we do build power projects, so we put in a bid for a solar PV project a month ago, and we of course knew what we proposed to build that project for, so you know, it’s a sort of primary data source like that. Then, we also are cognizant of what’s going on in the market, and Black & Veatch also, you know, although we build things, we’re not the cheapest company around, so a lot of people build things cheaper than us, so we look at what else is going on in the market that is in the literature, a lot of great reports out there, you know, data from the CSI for PV projects and things like that, so just a general sense of the market. And then, the third source is we do a lot of project work and a lot of our project finance activities, we’re privy, I guess, to sort of actual costs for actual projects that are being built or being financed by other people, so we kind of smush all those things together, for lack of a better word, to come up with these sort of ranges. And then, within the company, we have designated experts in each of the technology areas, and that's what they do all day long, is focus on these technologies, so every six months we come back and ping them and say, you know, this is what we said last time, is there reason to move things around a bit? And you know, they don't necessarily go through an exhaustive process every time, it's sort of their expert opinion based on kind of a merging of those three things.

MR. RHYNE: Good. So, Ryan, you said a couple of times something that really caught my attention, and I was wondering if I would be characterizing it correctly to say that – you mention that the cost of the generation model produced by Black & Veatch for RETI wasn't really focused on producing accurate values per se, in other words, exact simulations of what the costs are for projects, but rather seemed to be focused on getting accurate cost differentials and getting an accurate kind of rank using that rank methodology you were talking about in terms of it's the relative costs that you were trying to get accurate, as well as the ranked cost with regard to its value in terms of energy and capacity. Would that be an accurate way to describe that?

MR. PLETKA: Yeah, I think that was definitely the focus. I wouldn’t say that the numbers are not accurate, I just – we did a lot of things to sort of simplify stakeholder consensus, I guess, is the best way to put it. For example, we didn’t bother differentiating rate of return expectations for a solar PV project vs. a biomass project, or you know, even economic life. They’re all the same. So, we wanted to – in some cases, those things I knew as a modeler weren’t necessarily the best way to model it, but it was the easiest way to get people on board.

MR. RHYNE: Okay, thank you. Any other questions?

MR. KLEIN: Ryan, those are all installed costs, I presume?

MR. PLETKA: Yes.

MR. KLEIN: 2010 dollars, okay, thank you.

MR. PLETKA: Yes.

MR. RHYNE: And do we have any questions online? All right, with no questions online, and if there are no other questions in the room, thank you very much, Ryan, for sharing.

MR. PLETKA: Thanks.

MR. RHYNE: All right, our next speaker is going to be Eric Cutter from E3, talking about the Market

Price Referent Model.

MR. CUTTER: So I'm going to start very much where Ryan just left off with that comment of not necessarily the best way to model, but the way you can get everyone in the room to agree on; that is what the MPR Model is.

So, I work at E3. Where we fit in to this kind of of range of consulting services, we'll often partner with an Aspen or a Black & Veatch who have more of the technical knowledge. Our role is usually to try and take that and translate it into policy recommendations, and so we did that working with Black and Veatch on the greenhouse gas cost model, on long term procurement planning, and this MPR process, our role was supporting the CPUC in advising on the model and, again, translating all the input and the technical information into a policy recommendation.

So, the MPR to me is a story somewhat like the Graduate. We have a very promising young boy who comes out of a very excited RPS legislation, we are planning a big bright future, he gets all sorts of advice from different well-meaning individuals who all have different ideas about what he should do with his promising career, and he ends up by the end so confused and flustered that he doesn't fulfill the promise that we saw in the beginning. So, the birth of the MPR, we're all very excited in 2008 or so, or 2005, we're going way back, we're going to implement 20 percent RPS, and then, in a very idealized scenario, what we want to do, or what the Legislature wants to do, is separate the costs of procuring renewables to that which we can attribute as a sort of market-based, what the utility would otherwise be buying vs. what's an above-market cost.

Just to give some background on the MPR, I don't want to go into all the details, but one thing through all the years it was often confused about the MPR because it was part of an RPS statute is it was only ever meant to represent the cost of brown power, so that was then applied to the different renewables and in that context, its purpose got a little mixed up. But we're looking very much at a specific purpose, one plant that is designed to represent what the market value of energy and capacity is in California.

So this model is designed to do a lot of things and, as I'll talk about later, it can't do all of them well, but its purpose is to be a very blunt policy instrument and try and divide that cost of traditional fossil power and help use that to determine the economics and the relative merits of the renewable contracts that were being bid in to each utility’s RFO. But fundamentally, even though it can often get interpreted in this way, it in no way represents an estimation of what the utility’s avoided cost is, so it’s nothing like a qualifying facility short run avoid cost calculation, and it’s nothing like a long term procurement planning expectation of what a utility might pay for procuring energy and capacity on the market.

So one of the main points is we’re thinking about issues in developing costs of generation models, and this came in to play in the MPR process, is how you define the contract that the plant is operating under is very fundamental to both the financing risk of what you assume about the financing cost, and the rate of return that is needed or implied, and as we’ll talk about, the capacity factor, how is this plant being dispatched?

So the MPR model, Joel alluded to in the beginning, is a cash flow model and this is just a summary screen shot, but it’s all driven towards that bottom line there where we want the cash flow that is returning to shareholders to equal our target rate of return for equity, which in this case is 11.98 percent. So that little check at the bottom is how we know we’ve done the calculation right if we’re giving the investors the right rate of return.

I don’t want to talk about the gas in great detail, but it is the driver for fossil in the MPR, it’s about 60 percent of the cost. This is one area where the MPR gets often misused because the MPR is designed to represent a long term fixed price for fossil, one problem is that it doesn’t exist in California, so we have to make up some assumptions to get there. But it assumes that the power plant owner, the day it signs a contract, also fixes its gas cost for the life of the contract, which is very different than in reality. But this methodology for the gas price forecast has gotten used in energy efficiency and others. It’s a fairly good, simple way of using NYMEX prices for the first half, and then transitioning to long run fundamental forecasts for the later period, and it’s in a methodology that has been adopted by the CPUC, so we’ve seen this get taken up in energy efficiency demand response, and in other proceedings.

So one point I want to make is this idea that the costs of a power plant are easy to discover; we found out that is not the case. So the MPR, again, is a bit unusual, we are limited to using public data for plants recently built in California. There was often talk of trying to use the cost of generation inputs – or, model – because that represents a wide survey of many more plants. We were limited by the legislation to using publicly available data and, since the cost of generation was an aggregation of proprietary survey data, we couldn’t use that. But the first thing that stands out is we had to go look in detail at a bunch of documents to try and find out what was and was not included in each of the costs, and you can see we have to break out whether there’s dry cooling, whether any of the environmental or funds during construction are in or out of the base cost estimate in that area by plant.

And then, in the last round of the MPR, if you remember, in 2008 and ’09, we were dealing with rapidly inflating prices and inflation for raw materials, so steel, copper, all those costs were going up quite a bit, and this led to a challenge in the MPR where the plants we had data for were from 2005, 2006, or before, and the argument in the proceeding were that just inflating those costs up to 2008, 2009 and 2010 prices was not sufficient to represent the actual run-up in recent prices. So we ended up with this complicated process, which I’m not advocating, but it points out the things that come up in these proceedings.

And this Palomar example is a good one. Again, we had a document in 2004 that had a price for a plant that was going to be built and online in 2006, so how do we escalate that cost to 2009? If escalation was nice and stable, we would just take the 2006 number and escalate it to 2009 or 2010, but what we ended up doing, because the expected rate of escalation changed so dramatically, is we de-escalated our 2006 price back to the date of the document which was 2004, using what we assumed was their cost of escalation, so roughly 1.5 – 2.0 percent, and then we re-escalated from 2004 all the way forward to 2009 with the more recent Handy-Whitman Index that had a much steeper escalation for capital costs. Again, this was designed to represent in 2009 the idea that steel and cooper were driving up and the labor shortages were driving up plant costs. It all sounds very quaint now.

One public source of escalation, Handy-Whitman is proprietary, but the Army Corps of Engineers publishes every six months an escalation index that has a break-out – I think it’s line number 9, which is for hydro plants or power plant, so we used that. One other element of the model in the long run, levelized cost of energy, we – and this is an example of a bug in the model that is fairly fundamental, that survived for three years before we manage to – we weren’t looking for it, it just – PG&E, I think, was finally the one that pointed out, so the MPR, we have 10, 15 and 20-year terms for an MPR contract and, originally, we had the model, just calculated a 20-year MPR, and then for the 10 and 15-years, we just took the first 10 years of the model, the first 15 years of the model, so that would essentially, if you look at the blue line, just be cutting the blue line at 15 or 10 years. Again, three years of lots of eyeballs on this. It was finally 2008, PG&E realized that that is over-representing the cost of the shorter term contracts, so we had to switch to escalating the fixed cost in the MPR model year-by-year, and then levelizing based on those costs for 10, 15-year, and 20-year periods, and you see you get the more accurate representative costs. The MPR model for those shorter year contracts assumes no salvage value or cost recovery after the contract, so it just assumes that, at the end of the contract, all the remaining costs are going to get picked up by somebody else in the subsequent contract, which works out fairly simply for modeling purposes.

So financing – this, I think, will be a big topic of discussion for today and it was in the MPR model. Again, in the litigious environment – so we have the regulatory process and the utilities are eager to have the MPR reflect a lower value because that’s less that’s coming out of their ratepayer dollars, and more that's coming out of the State, of Supplemental Energy Payment funds. The renewables advocates are the reverse, they want to see the MPR be as high as possible. So we sit down in a room in 2007 and we're arguing about the cost to capital, the utilities with a straight face say any asset that has a long term contract with a fixed – long term contract with a credit worthy utility, that would have a financing cost of a credit worthy utility. And, you know, there's some legitimacy to that argument; it struck us as overly optimistic that you'd get exactly the same financing as a credit worthy IOU. The renewable advocates are in the other direction, they want to see the MPR represent an un-contracted merchant plant, so if you remember in 2008, Calpine and merchant are in fairly dire credit straits, and so they have very high costs of capital. So they are arguing to use those. As a result, we end up with a very just negotiated solution, the reason we sort of like this is it comes out in the end with a number that seems reasonable, but it's one approach to having a public method for calculating a cost of capital that can be updated, which is simply looking at bond ratings for either a risk-free rate, a Treasury, or in this case, for bonds – this was a mid-size industrial with sort of a medium credit rating and we take an average of some of those quotes, add them up, and we get a cost of capital for the MPR. A few of the data sources, just for reference, there is a Professor at NYU who compiles a bunch of data that is fairly updated regularly on cost premia, risk premia, and then there is now owned by *Morningstar* Ibbotson also publishes reports on a regular basis that I think now – they're not quite as expensive, you used to have to buy a book that costs like $3,000. I think they are more reasonable now. So, back on the contract terms, one interesting point is we're talking about a fossil fuel plant, whether it's an MPR contract or an un-contracted, has a dramatic impact on the risk we assume for the contract. The MPR, as we defined it, again, it doesn't exist out there in reality, but as we defined it, had very low risk, we're assuming no gas price risk because it has a fixed price hedged gas contract, no energy price risk because it's got a firm off-take with a credit worthy utility, and we include in the MPR in 2009, there is a cost for reserves, so that is accounting for some of the credit party. But if we were trying to look at another contract for the same plant, it could look very different.

Greenhouse gas, of course, is an issue. In the MPR, we used a survey that continues to be used, produced by *Synapse*, it's getting dated, and it's not a particularly rigorous methodology, it's an average of a bunch of forecasts based on very different legislative scenarios, but this represents an issue we ran up against in December. We were trying to update the costs for the Demand Response proceedings and we go to re-enter the gas prices in our avoided cost model, and you'll remember that the ARB published their rules in December, saying they were going to become effective in 2012, so when we looked in 2011, the gas prices looked fairly flat for the longer term contracts, and for the dates in December, but then, after those rules are published, just before the 16th, we see a noticeable bump in the forward electricity prices. And so that implies to us that the market is now imputing some greenhouse gas costs in their forward costs of electricity.

In this case, we punted, we just used the price quotes from before December 16th, but this is going to be a challenge going forward now, how much does the gas price forecast include in it implied GHG cost. And, of course, it's not going to be 1:1, there's always going to be some kind of discount for uncertain future, so we can't necessarily just assume that the gas prices include all the appropriate greenhouse gas costs, going forward.

So, I'm just going to touch briefly on the problems with the MPR from a procedural standpoint. We end up with a problem where everybody knows that the IOUs are short renewable energy and, so, the MPR, rather than becoming kind of a competitive differentiator between market and renewable energy, ends up becoming somewhat of a floor because the producers believe that they can go get a contract with the utility at least at the MPR or more, and we saw this with other solicitations in California, say, for the municipal utilities, they would be getting feedback that "you have to pay me at least the MPR because I know I can go and get that from the IOU." So, it becomes very uncompetitive, it serves as sort of an anchor and almost a floor for renewable energy prices. And when we have a net short position that's so large, we can't assume that the solicitations are perfectly competitive anymore, at least in terms of the prices they're bidding. And then the other main limitation was we ended up with one single price that's applying as a benchmark for all renewable technologies, so you end up overpaying wind because that's an established technology that's relatively cheap, and underpaying, say, solar power tower of concentrating solar thermal. And so you really end up with a single benchmark that's not doing its job in either case.

So I mentioned the over-constrained problem and this is one limitation to any model that is trying to be all things to all people, but the main challenge for the MPR was coming up with an assumption on capacity factor because we’re supposed to represent on-peak and off-peak prices, we’re supposed to represent the capacity vs. as available energy. So at one point in the MPR, we have this rather convoluted economic dispatch so the IOU’s each have a time of delivery factor that is part of their renewable solicitation. We apply that to the flat levelized price of the MPR, and then try to calculate in each Time of Use period would it be economic for the plant to operate or not? And then this ended up with an iterative process that, again, was convoluted and really didn’t make a lot of sense, but we got to capacity factor. Because that didn’t seem to work very well, and the best solution ended up being just assume that the plant is running at its technical capacity factor, and those two factors are from the Cost of Generation Report, we know that’s unreasonably optimistic, and then, so we married that with the time of delivery factors from each IOU. So the way the MPR is designed to be used, you have a generation profile for your renewable, you apply the time of delivery factors, and that’s going to give you your adjusted average MPR.

So it’s easier to explain in an example. In 2010, we have an MPR -- I believe this is a 2010 20-year contract –- so the price is $97.00 per megawatt hour. If you bid a solar project, so you have a solar profile which is more on-peak than off-peak, and then apply the TOD factors of each utility, each of them are slightly different, you end up with a PPA price that is somewhat higher. So this is, in a way, reflecting a lower capacity factor, in a way reflecting the higher value of energy during on-peak periods. But it’s a simple methodology that, again, is not really well-suited to try and do all these things at once.

So one thing to note here is for, say, a PV project to get a $97.00 price, PPA price, all they would have to do is bid in a price of $84.00. If you adjust that by the TOD factors in FCE, you end up with a contract price of $97.00. And this is how we see in the press often solar is claiming to be the MPR, and maybe in some cases they are, I’m not sure, but the main problem is the price being quoted is not always clear and so, for one, the MPR price is low because if you just look at the MPR table, it’s pre-TOD factor adjustment. The other main factors are, often PPA prices are quoted not only before time of delivery adjustment, but either in a first year price or in a price that escalates over the term of the contract. So it's quite possible you are looking at a solar PPA that is quoting a levelized first-year price, which would be the bottom quadrant on the right of this graph, but after you do the TOD adjustment and you levelize over the contract term, it's actually equivalent to what would be in MPR a levelized cost of energy that's not TOD adjusted, which is the solid red line. So, all by way of saying we really need to know that the price is being tossed about, whether or not they are TOD adjusted or not, whether or not they are escalating, and whether or not they are a first-year price.

So as most of you probably know, the MPR is now officially dead and the 33 percent legislation takes the MPR out of the renewable contracting process, but it lives on because, once a model gets out there with the CPUC stamp of approval, it's very hard for other proceedings to resist, so the MPR was adopted as a benchmark for the feed-in tariff for less than three megawatt projects. So we won't be producing the MPR on a regular basis as part of the renewable solicitations, it's as yet unclear how often and in what form the MPR will be recalculated to support the Feed-in tariff.

So, as Ryan mentioned, the MPR is very much an example, it’s nice in that it’s a CPUC blessed model that’s gone through a lot of review and stakeholder process. On the other hand, the stakeholders are coming in with a very strong point of view and, often, the ultimate input and model assumptions represent more of a negotiated settlement than actual best estimate of what reflects a market reality.

A few things, but this might be more appropriate for this afternoon, but as we look forward in cost of generation estimates, the increasing penetration of renewables are going to present some more challenges. In general, the CAISO is looking at – they’re very concerned that, with a lot of zero marginal cost energy out there, the average energy prices are going to come down, the ancillary services prices we’ve already seen come down, post MRTU. This makes it even less economic for a fossil plant to run in the market – how are we going to recover the rest of those fixed costs to get the fossil plants we need to operate and provide the flexible generation we’re going to need to integrate all these renewables?

Another issue as we look ahead planning, we’ve always very much looked at capacity planning for planning reserve margin, meeting our peak-load plus 15 percent going forward. Probably some of the studies are suggesting that the limiting factor will now be how much we need to meet the morning ramp, or the evening ramp, or the load following with the forecast error that renewables introduce and, so, it won’t be looking at a standard just planning reserve margins for peak capacity.

Finally, as has been mentioned, the cost of generation model is very much not a value model, though it often gets used as such. The best proxy we have for the value of capacity, and this is used in the avoided cost proceedings an awful lot, is what the cost of a combustion turbine is. So that would represent a long-run marginal cost of capacity, the cost of building a new combustion turbine and subtracting out the revenues it could earn in the energy market, and then what’s leftover is your cost of capacity. That comes out, you know, roughly on the order of $100 per kilowatt year. On the other hand, with the economic slowdown, we see resource adequacy prices, so these are the prices bid annually into the capacity market. They are not made public, but they are roughly on the order of $25.00 to $30.00 a kilowatt year, so that’s much less than what a cost of generation model would come up with.

I wanted to mention two other things that I think have come up that are of interest, and these came up in predicting the demand response proceeding. We had not appreciated before the impact of temperature, particularly on this issue of what is the value of capacity. Not only is the output of a CT at high temperatures reduces, it’s on the order of 80 percent, so that takes a pretty big hit on what the value of your peaker is on a hot summer day, how much it could produce. And your heat rate also takes a pretty big hit, so what we’ve had to do in the avoided cost modeling is try and model the temperature each hour that these plants are going to operate, so that we have a better understanding, 1) whether it’s economic, what’s the economic dispatch, 2) what’s the value capacity and the cost of providing capacity on a peak day. And then, capacity factor is always a challenge, this is one method that is actually seeming to work pretty well, at least for now, for a combustion turbine. So one of the issues in the MPR and that Joel mentioned, that the COG has gotten some criticism for, is how do you justify a capacity factor for combustion turbine? Do you assume a low five percent as the cost of generation model data, you get a very high cost, levelized cost, of energy or cost of capacity. The market saw something closer to nine or 10 percent, and there has always been this question of how to reconcile what your model would say is economic vs. what we see in the market. One method that is, as I said, working pretty well for now in the avoided cost proceedings is dispatching a CT into the real time hourly prices from post-MRTU CAISO. And so, what we do is we look at the real time prices, which are a lot more volatile than the day-ahead, calculate the variable operating cost of a CT, and you can see that's pretty solid, but it's varying a little bit, and that variation is driven by those temperature adjustments described earlier, and then we rank the prices in descending order and you end up with the number of hours that a CT is going to operate. And it's a bit of trying to get an answer that we thought made sense and the party would agree to, but we do end up getting in the approximately nine percent capacity factor range, using this method, depending on the year, the gas price used each year. The rest of this is for reference and that's it. So, I'm happy to take any questions or defer talking more of these issues in the afternoon.

MR. RHYNE: Okay, thank you very much, Eric. Questions from the audience? Questions from our other panelists and modelers?

MR. ALVARADO: Al Alvarado. Hi, Eric. I'm just curious about the statement, you talked about how you were comparing the resource adequacy range of costs that's been observed vs. your levelized cost estimates, and it's about a quarter of your capacity cost estimates. Any speculation of what the difference could be? I mean, I would assume that a generator may have other revenue sources, so they're not going to be putting all their eggs just on the resource adequacy contract.

MR. CUTTER: So there's a couple of issues and this is has been a bit of contention in the Eastern markets, when you try and have a single price for capacity, in reality the cost for a new entrant is much much higher than the cost for an existing fairly depreciated plant. So now that we're in a period of excess capacity, our reserve margins are on the order of 30 percent, there's plenty of capacity in the market and it's true that a plant that is earning other revenues, either in energy or is fairly depreciated, can bid a much lower cost in the resource adequacy and have that be seen as economic. So I think that's mostly what we're seeing is a lot of excess capacity and existing generators that don't need to recover the full cost of a new generator, bidding into the capacity market. Back East, there's been a lot of controversy over – from the state side, of feeling that they're paying too much for a market capacity price that's being driven by new generation, so it’s more on the order of $100 a kilowatt year, and they’re arguing you are essentially paying existing generators a windfall that is far beyond what they need to be compensated to remain operational.

MR. RHYNE: So just to summarize, it’s really the difference between existing vs. new generators and which one of those are kind of falling on the margin.

MR. CUTTER: Right, it would be – yeah – the main difference.

MR. RHYNE: Okay. So, my question to you is, you mentioned early on the limited scope of what the MPR is intended to do in the legislation vs. kind of how it has evolved over time and how it’s been used. The Energy Commission obviously looks at a wide range of energy policy issues and questions. From your knowledge and background with the Market Price Referent and that model, could you see any areas where we either could potentially use that methodology, or should avoid using that methodology?

MR. CUTTER: Well, certainly avoid adopting the MRP methodology in whole, but the two areas where it has seemed very helpful is the gas price forecast. I know the gas price, the internal gas price forecast of the CEC are often viewed as somewhat politically motivated with some skepticism from the outside, you know, depending on the Governor and so that’s a potential method that looks fairly unbiased as using a NYMEX forward price for the early years, and then some average of fundamentals. And the reason we have to average the fundamentals is so we don’t reveal any one proprietary – the argument against that is you are averaging three forecasts that are forecasting -- completely inconsistent forecasting, very different worlds, but it is one way to bring the parties together. And then the other is the data used for one potential mechanism for the financing cost method that can be updated with publicly available sources, though Michele will talk more about some of the issues there. And then, otherwise, the model and the methodology are fairly similar to what’s used in the cost of generation, or the RETI model, there is nothing in the model itself that is particularly unique in that respect.

MR. RYHNE: And then, would you suggest or – I guess, what’s your feeling about the direction that the cost vs. real time dispatch approach that you mentioned towards the end, of comparing the cost of a CT vs. the real time dispatch from, I guess, a particular referenced year – is that something that is continuing to develop? And, you know, do you see it as having a potential going forward? Or how do you see that being integrated into your future modeling activities?

MR. CUTTER: We're using that in a number of the proceedings, again, that are looking at the cost of energy and it's proving a useful way that seems robust enough and representative that parties across the spectrum can buy into it, and it works much better than either just using an average of historical plant data because there is always the argument that history, you have older plants that aren't as efficient, that aren't going to represent how much a new plant that has a better heat rate is going to run. So, it's a nice balance of trying to look at the actual heat rate of a new plant in market prices. One disadvantage is, you know, we're looking at a shape, at least it's now post-MRTU, you know, before we were stuck with a PX shape from 2001, but…. So you are looking at a historical price shape and there are going to be those that argue going forward with increasing renewable penetration that's not representative of the life of the contract, so that's a challenge that's going to be hard to weave into that kind of approach. On the other hand, we don't have one better --

MR. RHYNE: All right, thank you.

MR. CUTTER: -- it seems to do a pretty good job.

MR. RHYNE: Any other questions from the audience or online? No questions online, no more questions from the audience. Thank you very much.

All right, so our next presenter is Michele Chait from E3, as well, talking about Pro Forma Calculator.

MS. CHAIT: Good morning. I’m actually going to take a slightly different approach this morning to the presenters that happened earlier. I’m actually not going to speak to a model per se. What I’d like to do, and I think it is in keeping with the focus of today’s discussions, is to really focus on some key areas of assumptions and modeling in the cost of gen model that could be improved in future versions.

The Cost of Gen Study strives to achieve the most current levelized cost estimates for use in program studies at the CEC and other state agencies. And there’s a couple of implications that arise from that. Firstly, you need to have an objective analysis, you need to make sure that you’re not tilting the playing field towards or away from any of the technologies that you’re looking at. If you’re going to take these assumptions and results and use them in a program type analysis, or planning studies – I’m too short for the microphone – what you’re trying to get at, and Ryan

Pletka alluded to this earlier this morning, you want to be able to model the relationships among the alternatives appropriately, but it’s not necessarily important to get the right answer.

The Cost of Gen model and the Cost of Gen Report produce assumption that argues in many other analyses, aside from planning studies, and it really is important that we arrive at the right answers because the Cost of Gen Study is trying to do a lot of things. E3 actually uses quite a few of these assumptions in its studies, I know probably five or 10 times a year, I’m pulling out either a CT cost or a CCGT cost and looking at components of the levelized costs, and it really is important when we’re taking these out of a planning study to get them right.

So, again, my presentation today, I’ve put it together with an eye of focusing on where we could add additional complexity and get the greatest impact from them, sort of the biggest bang for the buck, and I realize that a lot of time and effort goes into this analysis and I know it’s a lot of work and a lot of money, and some of these will be a wish list, but I’m hoping that this feedback is helpful.

My overriding proposition today is that the goal of the analysis that we’re using this data for should drive both the calculation methodology and the assumptions that we’re using. So, for example, if I’m putting together an IOU Revenue Requirement Analysis, I’m not focused on what’s happening with cash flow and cash taxes, I’m looking at what’s happening with book depreciation and how the rate base is put together. Similarly, if I’m using an IPP contracted project, I’m going to be building up an LCOE similar to what’s done in the Cost of Gen Study. If I’m looking at an IPP Merchant Analysis, I’m going to be looking at a plant’s heat rate and dispatching that into the market and trying to figure out what that plant is earning, and given California’s markets right now, we all know that that’s not going to be anywhere near the returns that we’re seeing as the input values in these analyses. If I’m looking at an LCOE calculation, I’m looking just at the asset, maybe at the busbar, or the delivery point. That analysis will not include full system impacts analyses assumptions such as integration costs, transmission costs, things like that, so you want to be really careful to make sure that the inputs and the assumptions that you’re making are appropriate to the goal of your analysis, and I’m going to be touching on this idea throughout my presentation today.

Some of the things I wanted to focus on are capital costs, costs of capital, some issues that come up in project finance, taxes, the treatment of dispatchable resources, and some things that you might want to include in a system cost analysis.

So, for capital costs, I know this is a big wish list, but very often I'm opening up the Cost of Gen Report and trying to figure out what is included, and sometimes I don't have the time to go into the actual Excel version of the Cost of Gen Model and pull these cost amounts out, so one of the areas I think could be more helpful is if we produced capital cost estimate in either dollars per kilowatt or dollars per kilowatt year, that is broken out into additional granularity. Some of the areas I think could particularly be beneficial include a break-out of the interest during construction, possibly the treatment of transmission upgrade costs, whether those have been included or not, I know they are reimbursed, but it's hard to tell in the model with a printed report how those have been included. A break-out in either dollars per kilowatt year or dollars per kilowatt of incentive assumptions, sales tax and property tax incentives, emissions reduction credits, whether there's been an incremental cost increase for the presence of a labor agreement, and land costs are another area I always struggle over because I never know whether they've been included in an operating cost or in the capital cost. So, from my personal perspective, it would be really helpful to just have a break-out of that, or some kind of a note in the report about where those are.

A lot of my presentation today is a talk on how we can get to an appropriate cost of capital. For IOU's, it's really easy because there's the cost of capital proceeding and there's a publicly available cost of capital, capital structure, debt rate, and equity rate, that we can use. The IPP cost of capital isn't public, but it's my assertion today that there are some basic principles that we can use to arrive at what that number might be. The first idea is that market returns are going to be achieved, and I say that because, on one side you have developers that are trying to get the highest return possible for their project, on the other side, typically we're assuming that there's a competitive bid process, and that process is going to force returns down to a market level. And the market level that I'm assuming means that the returns that this project is receiving are appropriate for the risk of the underlying asset. In finance, we have a fundamental principle that says that, as an asset's risk increases, the return needs to increase, too. And if that doesn't happen, investors are going to invest their money in a less risky asset for the same amount of return. So, you want to see, as risk increases, the returns are increasing.

So, when I say “risk,” what does that mean? Here are some small examples of risk. Some of these can be compensated for, either with insurance or within the contract structure, but these are some of the ideas. So we’re talking about California power plants. In California, we have the history of the power crisis, we have the regulatory and legal framework, weather, earthquakes; technology – is the technology new or established? Are there O&M guarantees, manufacturer guarantees on the equipment? Is the power plant merchant or contracted? What are the contract terms impacting your revenue? What is the credit quality of the entity that the IPP is contracting with? Is it a utility? Is it a robust contract? What are the expectations of the costs? For example, is there a take or pay fuel contract? Regulatory uncertainty also introduces a lot of risks. As we know, there is curtailment questions, cap-and-trade, once-through cooling, and the finance markets can also introduce risk in terms of the tenor of the debt entities are able to obtain and the inflation rates.

When I speak today, I'm speaking about an IPP cost of capital that assumes a certain structure, and that structure is a California Generation Asset. The asset is assumed to have a 20-year contract with a California utility. The contract terms have been made public through an RFP that is publicly available. And the cost of capital reflects the current low inflation environment. While there is a legislative mandate in place for the 33 percent RPS assets, it's our assertion that that legislative mandate isn't really a factor in pricing the risk because we're assuming either for a 33 percent RPS asset, or a conventional asset like a CT, or a CCGT, that the contract is already in place, and so that risk is not in the picture anymore.

What sources do we have to be able to price these risks? We don't have a lot, as I said before, because IPP returns are confidential. One publicly available source of this information is the State Board of Equalization's Cap Rate Study, capitalization rate study. This is a screen shot from the 2011 BOE Cap Rate Study. The Board of Equalization produces the capitalization rates for use in property tax evaluation, and they produce estimates of the cap rate or the discount rate for many industries, including telecoms and railroads. This is for electric generation facilities. And the over-arching idea of this is the Board of Equalization looks at companies it believes are comparable and have comparable risks to the asset that it’s trying to value. What it does, then, is it looks at – or, calculates the asset return for these companies, and that asset return is a measure of what the market perceives as the appropriate return for the risk of those companies. And then the third thing that the Board of Equalization does is it assumes a capital structure, so a percentage of debt and equity that is going to fund the asset and, with that capital structure, it produces an equity return. So what I’m going to do now is walk you through each of these steps. So, first, I guess, in the bright red circle here are the merchant generators that the Board of Equalization has selected as comparable companies for evaluating electric generation facilities.

So, I would argue that these comparables are not really comparable if we’re talking about valuing California contracted generation assets. NRG Energy, the holding company that is publicly traded, has 24,000 megawatts of generation, not only in California, but Nevada, Arizona, Texas, the Northeast, Australia, and Germany. Also included in this hold co. is a company that provides engine maintenance and parts, steam provider, Reliant energy, and an electric vehicle system of fast charging stations. AES Energy is similarly diverse, they operate in 28 countries, five continents, own 14 utilities. So, you can see that the risks and types of revenues that are being valued with these comparable companies are not just California contracted generation assets, they have a wide variety of activities.

Secondly, we're going to move on to looking at how the asset return for these companies is calculated and I have highlighted the relevant data in the red circle here. The Board of Equalization has calculated an unlevered beta of .75. All beta does is measure how companies move with respect to the market, so a beta of less than one, which .75 is, means that, as the market moves, these companies move less than that. The Board of Equalization has provided a formula for how to calculate the asset return. They've provided a risk-free rate of 4.37 percent and a market risk premium of 6.7 percent. So, when you apply this formula with these assumptions, you end up with an asset return of 9.4 percent.

So this is the market's idea of what the appropriate return for these assets is, for these comparable companies. What this means is that, if you invest in an asset of equivalent risk to the comparable companies, then a return of 9.4 percent is appropriate for that risk. An asset return is the same thing as the return achieved on the total capital cost of the asset, so the debt and equity combined, and it means that if an asset is 100 percent equity financed, so no debt, that is the return that you should achieve, it's 9.4 percent.

Lastly, we're going to move from this asset return to an equity return and to do that you have to add debt into the capital structure. The Board of Equalization assumes a capital structure of 45 percent debt and 55 percent equity, and when you do that and run through all the formulas and the calculations, you end up with an equity return of 11.86 percent. It's really important to understand that that 11.86 equity return is a function of the level of debt and equity that you have in the capital structure, and if you make the capital structure 30 percent debt and 70 percent equity, or 40 percent equity, and 60 percent debt, that number is going to change, and you cannot take it out of context.

So, as we said on the previous slide, we've got an equity beta of 1.118, it's resulted in an equity return of 11.86 percent. The Board of Equalization, then, recommends an equity beta of 1.2, which yields an equity return of 12.1 percent, and then makes some adjustments to that and, in the end, ends up recommending an equity return of 13.87 percent. So now we've moved from an 11.86 percent equity return to a staff recommended equity return of 13.87 percent, so we've moved up two percent.

So, to summarize this, on the last – I'm not sure what page this is in the study – but the staff ends up recommending a cap rate of 11.16 percent, so this is the same thing as your asset return. This, I think, is inappropriate for costing California contracted generation assets, and I think it's inappropriate for a couple of reasons. As I said earlier, it's pricing the risk of companies that I don't think are really comparable if you're talking about contracted California assets. Secondly, we're using this 13.87 percent equity return and, if you recall, if you look at just the straight calculations that come out of the finance formulas as we were looking at an equity return of about 11.8 percent; thirdly, this calculation that achieves the 11.16 percent uses a post-tax equity return and a pre-tax debt rate, and you either need to use a pre-tax equity return with a pre-tax debt rate, or a post-tax equity return with a post-tax debt rate, and if you make the adjustment to the debt rate, you end up with a cap rate of 9.74 percent, rather than 11.16 percent. And if you wanted to look at just the pure risk of the comparables, it’s about 9.4 percent, so you can see, we have about a two percent swing in what the comparables tell you the cap rate should be, and what the Board of Equalization Study tells you the cap rate should be.

So what price is appropriate if you’re trying to cost a California generation asset? This table shows some publicly available asset return assumptions that have been used over the past few years. Eric spoke this morning about MPR, they use an 8.25 percent asset return. E3, in our 33 percent RPS model, used an asset return of about 8.7 percent. The Cost of Gen Model used an – this was the 2009 Cost of Gen Model, I think – used a IPP cost of capital for alternative technologies, so that’s renewables, of about 8.5 percent, but for fossil assets, it used a cost of capital of about 10.5 percent.

We struggled in E3 to understand why there’s a two percent different in the cost of capital for fossil assets vs. renewable assets. If you’re going to assume that the assets, both assets, have a contract with similar terms and similar risk, it seems like the asset return for those assets should be similar. Now, if you’re going to assume that the fossil asset doesn’t have a contract in its merchant asset, there is a strong argument to increase the asset return, but at the same time, in California, such an asset would not be achieving a return of 10.46 percent, it would be earning much less money in the power markets. If you look at the regulatory mandate as a potential explanation, a regulatory mandate could increase supplier power for IPP assets and could actually increase the asset return that they're earning, rather than have a lower asset return than the fossil assets. My contention is that that's probably not happening due to a competitive bid situation, and so you probably end up at around a market return with no supplier power and an asset return of somewhere around 8.5 percent.

As we saw before, the asset return and equity return are linked and they're linked via how much debt is in the capital structure. The theory behind this is that, as leverage increases, equity becomes riskier and, as equity becomes riskier it needs more compensation, because, as we said earlier, the more risk something has, the more return it needs. Mathematically what's happening is increased debt, which is priced lower than the asset return, produces more returns for equity. The really really important point here is that, how an asset is financed doesn't impact the risk of the asset, so it doesn't impact the asset return that that asset should receive. So, as you can see in the table up here, depending on how much debt you have in your capital structure, you can produce a multitude of different equity returns. With 30 percent debt, with these finance assumptions, we have a 10.6 percent ROE with 80 percent in the capital structure, equity is very risky, and it is showing a 28.3 percent return.

So what drives the capital structure that can be achieved? Developers want to achieve the highest equity return possible, and what they do to do that is try to increase the amount of debt they have in their capital structure. Lenders want to make sure they get repaid and so they're trying to push down the amount of debt that they have in the capital structure, and something called a debt service coverage ratio is what lenders use to try to figure out how much debt can be lent into the project. The formula for that is operating profit divided by debt service. For a California asset with a good contract, usually somewhere around 1.4 or 1.5 for a coverage ratio was adequate. As projects get riskier, you usually see higher coverage ratios. One of the things we've noticed in our modeling is that, for a project with investment tax credits or production tax credits, we're not able to put so much debt into the projects because the LCOE's are quite low, and it produces a lower level of operating profit, and so we've found that we've had to adjust the capital structure down. And this is something that you might want to look at in your Cost of Gen modeling if you're looking at doing cash modeling, not on the IOU side.

Sometimes you'll hear people speak about WACC, usually that means the Weighted Average Cost of Capital of Debt and Equity Capital that investors are investing in the asset, that number needs to be a little bit lower than the asset return, otherwise your investors aren't receiving an appropriate return on their asset, they'll actually have a negative MPV and they won't be investing in that. Here, I've used cost of capital to mean asset return, I'm not talking about investors WACC. If WACC equals the asset return, then you're going to exactly achieve the target returns that you're modeling.

So, to summarize the cost of capital discussion, the asset return is really the number that you need to be looking at. You can't look at an equity return without understanding what leverage underpins that equity return, and what the price of debt is. You need to really think about the goal of your analysis and the risk of the underlying asset that you're trying to price before you can recommend an asset return. It's really really important because, if the asset return that you're using doesn't match the risk of your assets, you're not achieving the goal of your analysis. How the asset is financed does not impact the risk of your assets and it doesn't change your asset return. The equity return does change and it changes depending on how much debt is assumed. And from the work that we've seen in public, we think that somewhere around an 8.5 percent return for contracted California generation assets with a long term contract is probably about right.

Another topic I wanted to talk about today is project finance considerations. If you have an asset that has a project finance assumption, typically what you'll see is reserve accounts that have to be funded at financial close, some money put aside to cover future debt service in case the project doesn't perform adequately, potentially major maintenance reserve accounts, these are funded upfront and, so, they'll typically increase your capex requirements. It would be – if we're doing a future version of the cost of gen model, it might be helpful to be able to segregate these amounts out and be able to show the impact of what's happening on your capital cost with the project finance assumption. There's also upfront fees in addition to legal cost that can be incurred, and it might be helpful to be able to break those out, again, being able to model debt service coverage requirements associated with the project financing, and the implications on the capital structure for projects that have production tax credit and investment tax credits.

The timing of tax benefits – as everybody has mentioned earlier, typically in all of the modeling that we see on these projects in California, we assume that tax benefits are fully utilized in the year that they're available, and what that does is it produces the lowest possible LCOE. Now, depending upon the investors that you have and your structuring, you may not be able to obtain those tax benefits. So one thought we have is you could produce LCOE book ends, or dollar per kilowatt year breakouts of your tax assumptions, so you could show what's happening with your LCOE in the event you can't obtain those tax benefits at the earliest possible time.

Dispatchable Resources – we've spoken about this a lot this morning. One of the problems with LCOE analysis is that it's looking at a dollar per megawatt hour metric, and this metric is perfectly appropriate when you're looking at renewable resources that are driven by RPS regulations because what we're trying to price is the dollar per megawatt hour cost of energy that's been procured, but for dispatchable resources that provide capacity such as the CCGT and the CT, I'd like to argue that LCOE isn't really an appropriate metric. For these resources, you're looking at assets that provide both capacity and energy, and dispatchability means that the LCOE result can swing dramatically, depending upon what your assumption is. Now, the chart on this page is kind of an illustrative depiction of the LCOE for each of these projects and how much value can be attributed to energy vs. capacity. So you can see in the upper left corner resources such as wind and baseload resource such as coal, nuclear, and renewable solar provide relatively more energy and less capacity. As you move towards the bottom right-hand side of the screen, or the chart, you see that CCGT and CT assets start providing more capacity and less energy, but certainly, if you were able to run a CT for 92 percent of hours, you'd be pushing more towards the energy side. So, a thought for this, for the Cost of Gen Report, might be to classify your resources according to their attributes, so you could put the renewable and baseload resources into one table and price those using an LCOE metric; but for resources such as the CT and CCGT, you could price their fixed cost using dollar per kilowatt year, and their variable cost using a dollar per megawatt hour metric, but not combining those into an LCOE. And just separating those and providing the outputs might mitigate some of the confusion that you have when people are trying to compare a CT with a five percent dispatch factor to a baseload renewable resource such as biomass that's running with an 85 percent capacity factor.

Lastly, we had some thoughts on looking at system analysis vs. LCOE analysis. As I mentioned earlier, the LCOE analysis usually looks at the cost of a generation asset, either at the busbar or at the delivery point, it doesn't every take into account system costs such as transmission, distribution, integration, and potentially the capacity and energy values of these costs when they're added to the system. The LCOE shouldn't take into account any of those costs if you are trying to produce an LCOE that's looking at what the cost of that plant is. Similarly, if the goal of your analysis is to produce a system cost analysis, then you should absolutely take into account all of the system cost, but you're mixing apples and oranges if you try to start including some of the costs of integrating the assets into your LCOE analysis.

Time of delivery impacts are also typically included in your system cost assumptions, but the LCOE analysis is usually post-TOD, so it's reflecting the PPA payments that are actually obtained by your developer and that's such that your developer is achieving its target return with those post-TOD LCOE PPA payments. That concludes what I wanted to speak about today. And Eric has already told you a little bit about E3, so I won't speak about that.

MR. RHYNE: All right, thank you very much. I appreciate it. Any questions or comments from the audience? Any from the rest of our panelists?

MS. CHAIT: I've scared everybody off.

MR. RHYNE: Go ahead.

MR. MCGANN: I've got the green light to come on. Richard McCann with Aspen Environmental Group. A few questions. You mentioned that – you were talking about firms that aren't representative, these firms not being representative in California – of course, several of these did own assets, but I think they probably sold all their assets in California at this point, so are you suggesting that the BOE pull from a different pool? And which pool of firms should they be pulling from?

MS. CHAIT: Well, it depends what you are trying to value. If you're trying to value un-contracted generation assets, you'd want to value comparable companies that own a lot of those assets in the geographic areas where your plant is that you're trying to value. If you're trying to value contracted assets, then, similarly, you'd want to value but look at the comparable companies that own those type of assets, or have similar risks to that. I personally think it's really difficult to get a group of comparable companies that are publicly traded that are representative of the types of risks that you're trying to value, so I don't know that there are any.

MR. MCCANN: Right, so that leaves us back with the BOE if we're going to do this analysis, that we're back with the BOE dataset as publicly available.

MS. CHAIT: I would argue that it's not an appropriate metric to use.

MR. MCCANN: Right, but we need an appropriate metric, so that is the issue with doing the CEC work is there needs to be an appropriate metric.

MS. CHAIT: I agree with you.

MR. MCCANN: So we have to make a choice.

MS. CHAIT: Well, one of the publicly available sources I suggested is MPR. That is measuring a 20-year California generation asset with a contract.

MR. MCCANN: Right, except, as Eric pointed out, that was actually a compromise developed by the – dominated, essentially, by the IOU position in the proceeding, so that was also a problem that that one also is not really necessarily an appropriate metric to use. The Energy Commission is largely trying to draw from publicly available sources that aren't so much dictated by a regulatory process that is happening at another agency in which everything – actually, the negotiations happen in a back room under a black box. So, that's why this choice of using the BOE one, along with the fact that I think, in the BOE, that these companies have a stake in this outcome at the BOE, so that you would expect they would have an issue with this, as well. So that was just an observation about that particular one.

MS. CHAIT: One potential solution to this is if the BOE numbers were to be used in public proceedings such as this to determine the appropriate cost of capital for contracted generation assets, some work could be done to determine what an appropriate list of comparable companies is, and look at valuing those, and potentially produce a BOE study that produces a discount rate for un-contracted merchant assets and a discount rate for contracted long term California assets.

MR. MCCANN: Right, so I guess it would be a question, and in terms of the Energy Commission's planning process, would they be interested in breaking out the contracted vs. un-contracted resources that sell into the marketplace in their planning process, in that mix of resources that would be doing that. And then, one thing, when I was looking at the asset return impact numbers, there was at a point in the late ‘90s, early 2000’s, that there were a lot of assets with 80 percent debt – the phone company doesn’t like us [WebEx interruption].

MR. ALVARADO: I think our WebEx audio went down. I was just wondering if anyone out there can hear the discussion, please send us an email.

MR. MCCANN: Okay. So, in that breakdown, your calculation shows that they would be getting a 28 percent return and I don’t think the assets at that time are getting that kind of return.

MS. CHAIT: So this assumed, if you’d look, a 6 percent debt interest rate.

MR. MCCANN: Uh huh.

MS. CHAIT: That interest rate is likely not achievable for a project finance type of deal. I would imagine it’s closer to 7.5, 8.0, 8.5 percent. So if you plug that level of debt interest rate into these calculations, your equity return would drop commensurately.

MR. MCCANN: Okay, so that would be – so we might actually see – we’d probably see that the debt interest rates are actually going to adjust for the amount of debt financing, so, in fact, the equity returns would narrow substantially in between the different debt financing assumptions that are in that table that are there, then, I guess.

MS. CHAIT: Yeah, if you changed your debt interest rate, your equity return changes, and the debt interest rates that are in this table are reflective of an IOU. I believe the mandated cost of capital in the IOUs now have a debt interest rate of about six percent.

MR. MCCANN: Uh huh, okay. And then you mentioned that there’s a publicly – you were mentioning publicly available studies on the return – can you get those to us?

MS. CHAIT: Uh, these are publicly available models, so the MPR, the 33 percent RPS model is available on the CPUC website.

MR. MCCANN: No, these are modeled – these aren’t actual studies of the returns, these are actually models –

MS. CHAIT: These are in the models, yes.

MR. MCCANN: Oh, okay, so this is different than – I was thinking that you had done or were aware of studies on the actual returns on these projects, okay. Thank you.

MS. CHAIT: You're welcome.

MR. RHYNE: Thank you. Any other questions? Al?

MR. ALVARADO: Actually, we have a questions from someone on the WebEx, Mike Mendelsohn. We're going to unmute your phone.

MS. CHAIT: Oh, with NREL?

MR. ALVARADO: Okay, go ahead, Mike.

MR. MENDELSON: Hello?

MR. RHYNE: Yes, hello, we can hear you.

MR. MENDELSON: Okay, great, thanks. With all the uncertainty that you highlighted really well regarding the LCOE models, I'm just wondering if their use should really be limited to evaluating similar technologies. It seems like we're relying on LCOE models for really more than they're intended for, perhaps like portfolio development, or optimization. And we should just recognize that they can't do that outside of a production simulation model. Any thoughts?

MS. CHAIT: Well, I think there's a couple of things. I think that the cost components that go into the LCOE's such as the capital costs and the operating costs, I think that it serves many purposes to have a publicly available data source for those types of assumptions, and I think that the Cost of Gen Model does a commendable job putting those together and in the Cost of Gen Report. I do think that there are limitations to publicly produced LCOE numbers because I think they can be taken out of context and misused in analyses, unless you're really careful about understanding what the assumptions are that have gone into them and either adding in or stripping out costs or benefits that may not be appropriate for your particular analysis. And that's where increased granularity in some of the assumptions and in the breakdown of the components of LCOE, I think, could be really beneficial because it could help with more transparency in what's in the numbers, and facilitate better analysis.

MR. RHYNE: So just as a follow-on to that, if you could go to the graphic you showed kind of breaking down energy vs. capacity, this gets to perhaps a question for this afternoon, but I think you've teed it up pretty effectively here, and I wanted to ask you specifically, we refer to levelized cost of energy and it's specific to energy and the use of these models is, I think, as our WebEx caller kind of alluded to, has kind of gone beyond the use of these resources, I should say, it's gone beyond simply providing energy. I think, to some extent, it used to be that, you know, a new resource covered a multitude of sins, in other words, a new generation resource would automatically provide some degree of capacity and load following, and things like that. That's not the case, necessarily, by default anymore, and so there seems to be kind of a divergence of classes of generation types. And you've kind of made some case for the potential for breaking out not just levelized cost of energy, but to some extent a levelized cost of capacity, if I could kind of infer a little bit from what you've said. How would you see that working specifically with regard to a publicly released model similar to what we have now? And how would you recommend kind of dealing with the divergence, the apples to oranges effect that that creates between energy and capacity?

MS. CHAIT: Well, so these models are producing the cost of new generation, they're not measuring the market value of that capacity or the market value of that energy. For resources that provide a significant amount of energy relative to capacity, it seems like an LCOE metric is appropriate for those and, for renewable resources that are being procured under these RPS regulations, an LCOE metric is necessary, as well, because you're looking at the cost of procuring energy. For resources that, like CT and CCGT, I think, are the two key resources that we're talking about that can provide energy and capacity, but that are dispatchable, the dispatchability, I think, is the key distinction for those resources. It seems like if you can provide just the fixed cost, so fixed O&M and the dollar per kilowatt year capacity value for those, that’s giving you what the annual new build cost of that asset is before you make any dispatchability assumptions, and if you provide the dollar per megawatt hour cost of variable O&M and fuel, and the heat rate for the fuel could vary according to your dispatch assumptions, you could get an idea of what the costs are to dispatch that resource. So, if you’re maybe running mid-merit and turning up and down, you’d have a higher heat rate than if you’re running 92 percent of hours, so you could produce a curve that provided a higher dollar per megawatt cost for running less frequently and a lower dollar per megawatt hour cost for running more frequently, and you could combine those to produce a metric that’s relevant for dispatchable resources.

MR. RHYNE: So, it’s my understanding that, to some extent, that’s already captured in the screening curves that are there in the model, and perhaps you might have more specific comments in the written form that would help us understand how what’s there in the model doesn’t necessarily capture what your pointing towards because I think, to some extent there's already an effort to capture some of that underlying question, but we certainly are interested in getting to the heart of that breakout that you're talking about.

MS. CHAIT: I think one of the pieces, in my mind, that's missing as a user of this study is that the data is there, but it's not necessarily published in a form that I can readily extract. Like if I go to the curves, I need to sort of develop what that assumption is, rather than having in a table that, if this is the dollar per megawatt hour cost, and this is the dollar per kilowatt cost, or dollar per kilowatt year cost, but it's not necessarily published in that level of granularity, I have to go in and make the calculations, and that can take away some of the credibility of the work – if it's already published, I can point to it and say, "This is on page 24, this is the dollar per kilowatt hour cost."

MR. RHYNE: I see, so you mean the credibility of the work built on this particular model? Or do you mean the credibility of the model itself?

MS. CHAIT: Not the credibility of the model itself, like I could go into the model and produce a number of results, but it's more credible if I can go to you report and say, "Oh, on page 32, this is the dollar per kilowatt hour cost that is the result of dispatching it at 30 percent," for example.

MR. RHYNE: Okay, thank you. Any other comments or questions from the panelists or here in the room?

MR. SILSBEE: This is Carl Silsbee from Edison. I'm feeling that there's a lot of common thinking here and, when we get to our presentation this afternoon, I think we'll talk about the dispatchability issues that we have with the comparison of CT and CCGT, and I'll leave that for this afternoon, but I did want to comment that, while that may be a primary area of concern, there are some secondary concerns, even within similar renewable resources and we think there are some subtle mis-ranking that now exists between solar and wind, for instance, because they have different NQC values. And what we've tried to do in some of the proposals we'll make this afternoon is capture some of those differences, as well as the dispatchability.

MR. RHYNE: Okay, thank you. Anymore questions online?

MS. CHAIT: Can I respond to that really quickly?

MR. RHYNE: Sure, go ahead.

MS. CHAIT: This kind of illustrative diagram actually took into account the NQC values of each of these resources, so there is a lower NQC for wind and slightly higher for solar, and so on.

MR. RHYNE: Excellent, thank you. All right, last call for questions. Okay, so we've reached that rare instance where we are ahead of schedule as we head towards the lunch hour. Considering the depth and degree of conversation that I hope we achieve this afternoon, I'm going to ask that we still hold ourselves to a one-hour lunch. It is a quarter to 12 now. If we could reconvene at a quarter to one and get started just a few minutes earlier than originally intended, we can go ahead and have a thorough discussion this afternoon and hopefully get out of here, and if anyone has to commute, from there beat traffic. With that, thank you all very much and I will see you in an hour.

(Recess at 11:46 a.m.)

(Reconvene at 12:47 p.m.)

MR. RHYNE: All right, so our next presenter is going to be doing so remotely. We're going to work out just the logistics for a minute. I believe it is Mike Mendelsohn. Mike, if you're listening in, if you're on the phone, can you let us know? We're trying to unmute and trying to find you on WebEx here.

MR. MENDELSOHN: Okay.

MR. RHYNE: There you are.

MR. MENDELSOHN: Can you hear me now?

MR. RHYNE: I can hear you.

MR. MENDELSOHN: Okay, great.

MR. RHYNE: I'm not sure which user you are, but we've got you now.

MR. MENDELSOHN: Okay.

MR. RHYNE: Okay.

MR. MENDELSOHN: And so I'm going to have this brief overview and then I'd like to open up the models. I have them open on my machine. Or, if you have them, I can use your machine.

MR. RHYNE: So what we're going to do is we're going to transfer you presenter rights to our shared desktop here, and I'm going to ask our tech guy here to do so and give me the thumbs up when you're ready.

MR. MENDELSOHN: Okay, so I'll do the presentation, as well. Can you see my screen?

MR. RHYNE: I cannot.

MR. MENDELSOHN: Shall we use your machine?

MR. RHYNE: Yeah. Gene, just a second, I'm going to have you test. Okay, so you have presenter rights, go ahead and try test moving the slides forward and back.

MR. MENDELSOHN: It's not working right now. What buttons would I use, page down?

MR. RHYNE: Page up, page down.

MR. MENDELSOHN: No.

MR. RHYNE: Okay, so what we can do is I can advance the slides as necessary, I think.

MR. MENDELSOHN: Okay, and then how do you want to handle going to the model, itself?

MR. RHYNE: Hold on a second. And which is the model here?

MR. MENDELSOHN: It should say “CREST” if it’s loaded up. You could go to the website and grab it if you want to.

MR. RHYNE: All right, so apologies to the folks who are sitting through this, real quickly. What’s your site?

MR. MENDELSOHN: It is Finance – no www, just financeRE.NREL.Gov. Yeah. And then if you click on that main picture right there, and then go down to open up CREST on solar, good. Okay, I’ll just go back to the presentation.

MR. RHYNE: Okay.

MR. MENDELSOHN: All right, thank you very much for inviting me. My name is Michael Mendelsohn with National Renewable Energy Laboratory. I’m going to be discussing quickly the CREST model, Cost of Renewable Energy Spreadsheet Tool, that was developed by

Sustainable Energy Advantage on behalf of NREL. And I’m first going over some of the activities that our finance team at NREL is undergoing and then it explains the genesis of the details of the CREST model. You can move forward. Great.

So our Finance Team is involved in three general activities, first sort of collecting data and information, developing tools and policy analysis that helps to utilize our data, I hope those in the industry evaluate renewable energy projects and understand some of the concepts around project financing, and then visualizing that data and policy analysis and tools so that they’re easily digestible. Next slide.

Among our data information activities, one of our primary efforts, is the Renewable Energy Finance Tracking Initiative. Here, we collect and aggregate renewable energy finance-related data, cost equity, cost of debt, the form of depreciation taken by technologies and other factors, and make that available to the public so that people can populate their models as effectively as possible so they can get good output from their model runs. Next slide.

We’re also helping the SAM team, the System Advisory Model, which they plan to present and will be discussing, incorporate more complex financial structures into the model, including sale leaseback as pictured here, as well as partnership flips and leveraged partnership flips. Next slide.

Some of the content that we’re developing include guide to geothermal power finance and other data that’s available for policymakers and new investors, new developers, to get them acquainted with renewable energy project development. Next slide, please. Next slide again.

Some of the other content we make available through either weekly blogs or what we call feature analysis include evaluation of Dodd-Frank Regulations and, again, looking at geothermal energy cost inputs, tax equity situation in the markets, including charitable organizations as part of your renewable energy project finance development. So, we encourage everybody to take a look. It’s, again, our content is available at this website, financeRE.nrel.gov, including our tools, including the CREST models that I’m going to present today. Next slide, please.

AS part of our visualization effort, we developed this website, again, it’s a very excellent searchable website, where you can look for content and using a wide variety of filters look at our activities, including the blogs that we developed, as well as the tools that we make available. Next slide, please.

As part of the CREST models, Cost of Renewable Energy Spreadsheet Tools, this was born from a partnership that the Department of Energy has with the NARUC. There was a need that we saw to develop sort of a simple, yet robust tool that could be easily utilized by the policymaking community. There are three CREST tools developed to date, one for geothermal solar and winds. We had three different sponsors from the Department of Energy – I always want to thank our sponsors for supporting our efforts, and that includes within the Department of Energy the Geothermal Solar and the EE Corporate Analysis Divisions. NREL hired Exeter Associates to develop the models and Jason Gifford of Sustainable Energy Advantage was sort of the primary author and developer of the models, but the team also included some members of Exeter Associations, as well as the Meister Consulting Group. In developing the models, we worked with several public utility commissions that were part of sort of our development team, including the PUCs of Colorado, Hawaii, Michigan, and Washington State, so we'd like to thank those individuals for helping us out. Next slide, please.

Some of the project objectives was really to create a toolkit for cost-base rate setting in the U.S., it’s not just the models, but there is also a detailed report that should be out if not this week, then next, looking at all the FIT policies across the country and the models that are available, and doing a good analysis of the pros and cons of each of those models. There is also a User Manual for the models for ease of use. The CREST models were one of the aspects of developing and was to cherry pick the best features of other public models, so we looked at essentially ease of use of the RETI models and the models done in California, as well as NREL’s SAM, and tried to see what features would best fit the policymaking community. We’re trying to balance, again, ease of use, but also provide a relatively rich feature set. We also wanted to develop models that didn’t have any macros, weren’t prone to breaking or being misunderstood, something that was pretty robust in its use, and also something that provided immediate feedback on a wide variety of inputs of concern. So, some of those inputs include size and performance and capital costs, O&M, financing, ownership and tax incentives, and reserves and depreciation. Some of the constraints – it’s not really constraint, but it’s more of something we highlight when, in developing the models, is debt service coverage ratios, its minimum and average DSER’s are violated and we just put a big red flag so that policymakers don't assume that projects can take on a huge quantity of debt at low cost in order to develop these projects. The basic outputs are the Year One cost of energy, as well as the levelized cost of energy. Next slide, please.

The CREST models are available and free to the public at this link within the FinanceRE website, or we encourage people to Google CREST model if it's confusing to get to that hyperlink. The models are protected outside of primary inputs, it's not an open source model, and we did that to sort of protect the name of NREL so that it doesn't look like we're supporting their results of model runs that we couldn't really validate. Right now, we're having trouble getting the MAC version of our models working properly because of the protection we've applied to them; that protection goes down to the cell level and MAC versions of Excel don't allow cell level protection right now, so we're trying to work through that issue. Again, the user manual is available and the analytic report is to come shortly. Next slide, it should be the last slide.

Okay, so now if you could open up the model. Thanks for your help with this. And I apologize to everybody that he couldn't be there today, he was looking forward to it, but we're under relatively strict travel guidelines we're trying to follow. So there are six tabs to the spreadsheet tool, this Introductions tab can get you to the User Manual and the important references, and give you a guideline to how to utilize the model, and some of the basic backgrounds. Most of the model, if you can go down a little bit further, okay, we can go over to the Inputs tab, great, thanks, so the user can select between photovoltaic and solar thermal here in the solar model, all the yellow cells indicate a dropdown menu is available underneath that cell. The other cells in bold blue indicate an input and the cells in sort of plain black text indicate an output. Here at the cells that are green under the check columns, that indicates whether or not you've violated some sort of constraint on the input, whether it's the input won't allow for a negative value, for example, or a non-numeric value, so the model will let you know if a value that's outside of relatively broad guidelines. If you click on one of the question marks in the Notes cells, these note cells are there to guide the user to utilize – be able to understand what's requested of you by the model, what kind of information the model is looking for, and maybe give you hyperlinks to useful reference points. All right, thanks.

Here, in this first primary box, we're looking for project size and performance, what the capacity size is, the conversion efficiency, and the capacity factor, and production degradation. One of the key features of the model was we're trying to – a lot of people look at and come at the modeling approach in different ways, so if you could click on that Intermediate yellow box under Capital Costs, and you'll see that here we have three different options within the Capital Cost input, and if you could click on "Simple," then the user can essentially utilize this simple level of capital cost input and insert perhaps 475 or another value as a signal value for the developer lot cost to develop their project, or, if you could go back to Intermediate, then there are four different levels of input data within Intermediate here, Generation, Balance a Plan, Interconnection, Development Cost, so we make that available so that users can approach the problem as they see fit. If you get a pound [#] and an "A" like that here, that's because you just need to recalculate the model, there might be some reason, so if you hit F9 once or twice, then the model will resolve itself. If it's because there are no macros, sometimes you have to hit F9 to let the model recalculate.

There is also an opportunity to put any far more complex inputs under the Complex Inputs tab, is our box is here so that you can put in a wide array of line items for the form primary items that were back on the inputs page, generation equipment and balance a plan, or what have you. You can click on this hyperlink to go back to the inputs worksheet. There are hyperlinks within the spreadsheet that allow you to go between tabs toward the specific table, allowing quick input of detailed information if you so choose. Scroll down a little bit.

Here, again, up a little bit, yeah, a little bit more, okay great. This next box is on O&M, Operation and Maintenance. And, again, the user can select between different levels of input detail. You could start from the intermediate drop down box there and go to simple. So, here, the user can select between – or input Fixed and O&M Expenses quickly – I'm sorry, Fixed O&M or Variable and other expenses. There is also an opportunity for essentially a single elbow, or two periods within the O&M inflation analysis, so you can select perhaps a two percent inflation rate for O&M up through the end of Year 10, or a different variable, but allowing for two components of O&M Cost Inflation in your forecasting process. And if you would go to the Intermediate level of O&M detail. Great, thanks.

And here, if the user chooses, besides fixing the variable, you can also incorporate insurance, project management, property tax, or pilot, land lease and royalties, so an additional level of detail that you can provide on your O&M as necessary.

Here in the next box are construction finance. If you selected this simple level of capital cost up above, then – yeah, if you go to “Simple” there, you’ll see down in the Construction Finance, that blanks out because essentially we’re saying it’s only going to cost 475 on an installed basis. But if you choose intermediate or a more detailed level of inputs for your capital costs, then there’s an opportunity to forecast, if you press F9, it should open up again, hopefully – yeah, I guess that didn’t take for me, great. If you go back up, yeah, there under Construction Finance, you can input the tiered in months and the interest rate under construction finance. Here within the permanent financing section, you can look at your percent debt and your debt tenor and the interest rate on that debt. There is also an opportunity to put in the lender’s fee because that can be a very relevant cost. Here, we have three percent of a lender’s fee for the debt associated with the project. As I mentioned, we put in pretty big flags for debt service coverage ratio. If you can increase the percent debt up to 70 percent or something like that, in this first box, yeah. Sixty, that should get the job done, and then hit F9, okay, yeah, that might not work, great, thanks. And if you hit F9, the model will recalculate, you see that the model is indicating that you've failed the minimum and average debt service coverage ratios, so we made this as sort of a critical feature because we think that's something that happens in the policymaking world, that you could just load up – there is an assumption that you could just load up with the cheap debt, so we really wanted to highlight that aspect and that sort of forces the user to put it in a lower, more reasonable level of debt into their projects, to make sure that those minimum and average debt service coverage ratio constraints are followed. If you want to change that back to 40, that would be great.

There are detailed notes. Great, thanks. Here just below in the third to last cell in this box, we have the target equity IRR currently set at 15 percent. The equity IRR, we're really drawing on how much cash is flowing to the project. If you wanted to load up more debt, for example, they'll let you pass your debt service coverage ratio constraints, what you really have to do is increase your equity IRR to a lot more cash into the project and that will allow taking on the higher debt percentage. So those two things are highly related within the model development. If we can go down a little bit? Great, thanks. This next box is just sort of an output of how much debt and equity is involved in the project, just to give the user a better sense of where the source of funds is. Here in the final box on this left side, we're just asking is the owner a taxable entity, you know, can he take advantage of the tax credits that are currently available, including depreciation benefits, what the Federal and State income tax rate is, and whether the tax benefits can be utilized as generated, or only as the project can utilize them on a cash basis. So, if you pull down that "As Generated?" That asks the user if the cash benefits should be carried forward as generated. Generally, with a tax equity investor, we're assuming that the tax benefits can be utilized as generated, that the tax equity partner only got involved because they had a tax liability somewhere else on their balance sheet. But that's the idea there, is it strictly at the project basis? Or is there a tax equity investor that can utilize the tax benefits outside of this particular project? If you could go up to the right? I apologize for going a little long. The idea here on this top box is to understand, if there is – if the project will outlive the Feed-in tariff, and here, if you put in 20 years for that Feed-in tariff, then this other box will open up and the user can input what the market base revenues are expected to be beyond the duration of the Feed-in tariff, that’s the idea there. Just below in these next set of boxes, we have Federal and State tax incentives. If you can go to the cost-based pull-down, the top of that Federal Incentives there, you can define whether it’s a cost-based or performance-based, it’s like the performance base – great – you’ll see that this bottom set of rows will open up, asking you more detail about the performance-based Federal incentives, and if you can go back to the Cost-based, you’ll see only the top set of rows will open up, asking you if it’s cash, grant, or if it’s a tax credit type of incentive, and then how much can be utilized. The N/A is there again because the model needs to be recalculated.

So, we kind of see the model as similar to the RETI model, it’s in that – it was completed with no macros and supposedly – supposed to be relatively concise and easy to understand for someone who doesn’t need a bank quality financial analysis, but that wants to do something quick and dirty, but perhaps a little bit more than RETI, and that you have a lot more opportunity to put additional detail into your project model. Here down below in the Fee Incentives, there is a very similar input here where you can put in either State or Utility-based tax incentives or cash. Here, it’s offering you whether the incentives are cost-based or performance-based, and if you select on performance-based, you’ll see that the bottom set of rows will open up and it’s asking you – the model is asking you if those are tax credit incentives or cash incentives, and then some of the detail about that. We can go down now to the next box. Here on Capital Expenditure during Operations, there’s a replacement such as inverter replacements, you have the opportunity to put that in, and then reserves funding from operations for intermissioning reserve, you can select between whether that’s paid for out of operations, or it’s expected to be paid for from the salvage value of that equipment. And here, just below that, there’s an opportunity to specify what the debt service and O&M reserve, what the capital reserves represent on a monthly basis, whether it’s six months of expected expenditures, sort of a normal input. Then, we have the opportunity for depreciation explanation, whether the depreciation has a bonus quality to it, and what percentage of it is allowed by bonus, and then you could specify within the four primary categories of your investment whether that's on a five-year MACRS or other depreciation category, you can define whether it's 100 percent, how those are broken out. And if we could go to Summary Results on the next tab? All the results are indicated here. We don't have a very sophisticated Results page, we're going to make some improvements probably to this section in our next version, but essentially this will give you the Year One Cost of Energy and the LCOE, as well as some of the primary inputs that were utilized in that run. So, you could grab those cells, essentially, and copy and paste them as values, and then put a name over – yeah, if you could just grab those cells right there and then copy and paste that there? Yeah, and you could even grab all the way down to the bottom of that, okay, thanks, and then name that scenario and then adjust your assumptions and do the same. It's not very sophisticated, just time frame – we're trying to, again, limit how complex the model is to really specify the ease of use.

If we can go over to the next tab, Annual Cash Flows and Returns, this is sort of a very quick look at the project cash flows on a year-by-year basis. Here we see – you might have the tariffs or market value of the power, the total revenue, operating expenses, debt service, you know, primary output of cash flows, including tax benefits and liabilities, the Federal and State basis. If you can go down a little bit on this page? There are some primary graphic output here, including cumulative cash flow on the left, and revenue and tax benefits and liability vs. expenses and cash obligations on the right. So that's sort of a primary output of the model and those come from the data provided above, as well as some rows to the right, or columns to the right, of what we're just looking at. If you can go to the next tab, this is more detailed cash flow where we can really see the waterfall of revenues and expenses and get a really good handle on how the project is operating on a year-by-year basis. If you go all the way down, in order to develop a model without any macros, we sort of borrowed from Black & Veatch's sort of those hidden data tables that worked so well, and that's here at the very bottom where – yeah, right there where it says "MPV," so the model essentially is solving for when the results turn from negative to positive, and then brings up an order of magnitude to solve between 45 and 46 cents, and then one more to the right to solve between a 45.6 and 45.7 cents per Kwh, so it's taking that and continually moves up an order of magnitude so you can get a finer detail on solving the LCOE without use of macros, kind of a nifty little tool.

And then, here in the complex inputs at the last tab, I should have showed this quickly before, but if you had selected the complex inputs on the first inputs tab, then you could put detailed information under generation equipment and indicate the eligibility for the IGC and the depreciation classification, so you could go to the left a little bit, if you go to “Complex” there where it says “Intermediate”, click on that pulldown where it says “Intermediate.” Go to Complex. And then there’s a hyperlink here, click Complex Input Worksheet, see the hyperlink at the bottom of these blank cells on the left? Yeah, so that will take you right to this sheet, or you could always click on the tab itself. And then you have the opportunity to put details, generation equipment information here, including this – you could select the depreciation classification on the right for any single line item. Right, perfect. And if you go down just a little bit on this page, you could see that we have similar opportunity to put the balance of plan information here and then develop it a little bit further, this is either connection information, substation, transformer, so really a lot of opportunity to put very detailed information there if that’s what the user is looking to do, development costs and fees, and then there should be some sort of financing and then there's more detailed information for – and this table here is just sort of summarizing everything that is going on above, so it's all on a single page. Great.

So that is the solar model, but we don't have all our technologies on a single model. The wind model is very similar, as you can imagine. The geothermal model, because geothermal development is so unique, with our exploratory well development and depletion of the resource, as well as heat rate degradation, there's very specific inputs that are fine tuned for geothermal development, as well as classification of the depletion allowance and the like, so if you're interested in that, I would encourage you to pick up that model and take a look at it. And that's all I have for now, if there are any questions that you have.

MR. RHYNE: Thank you. So this is Ivan Rhyne again. I wanted to ask, and I appreciate the time you took to go through the model itself, it looks like you kind of had to make some tradeoffs, or you chose to make some tradeoffs with regard to simplicity vs. completeness, although you do have quite a bit of room for additional information there in the model. But what I don't quite see, and perhaps I missed it, you built a lot of default values in there with regard to solar. Where are you pulling those default values from? What's your primary source of input for the choices you make with regard to those?

MR. MENDELSOHN: Right. For these default values, we really just relied on the model development team to put in reasonable default values for this version, so it was more of a consensus on what's necessary by the development community that we relied on, including the subcontractors, but then the results are like a team of evaluators that helps look at the model. And I think Ryan was also involved in looking at it. So, yeah, I mean, the defaults are reasonable, but they're not fine tuned to be very exact; we're hoping that people will have some forethought in evaluating those and making them relevant to the project.

MR. RHYNE: Okay, thank you. Any other questions here in the room?

MS. CHAIT: Would you consider releasing a version of the model without protection?

MR. MENDELSOHN: You know, we're discussing it now. It would make our lives easier in some ways and harder in others. But we want to get rid of the MAC incompatibility issues and I get asked that question pretty much every time I present the model, so far. So, we recognize there's a desire for that, but to date we haven't – we're looking at that policy.

MR. RHYNE: Okay, any other questions here in the room? Any questions online? Okay, so having no questions in the room or online, thank you again for the presentation. I'm under the impression you're going to hang around and join us again in just a little while for the panel discussion. Until then, our next presenter is also going to be presenting remotely and he is Nate Blair, and if we can unmute Nate? Nate, if you're online, if you'll just start talking and make sure we can hear you.

MR. BLAIR: Hi, this is Nate.

MR. RHYNE: Here we do, we can hear you. Thank you. And I think we're going to have to work with the same kind of structure as before, we have somebody here who can click to the slides, so if you just want to give us the cue when you want to go to the next slide, we'll do so, and take it away.

MR. BLAIR: Okay, that's great. And unfortunately, my model, I don't think you can download it in a few seconds like Mike's, so I'll try to talk you through how cool it looks once we get to the demo part.

First of all, I'm Nate Blair, I've been at NREL about nine or 10 years and have been doing a lot of system simulation and software modeling throughout my time at NREL and before that, and I stand here as part of a much larger team, of course. Next slide, please.

So, SAM, as we call it, used to be called the Solar Advisor Model, and we now call it the System Advisor Model because we've added several non-solar technologies which we'll get to in a little bit. It's a computer program that calculates the performance of a model, the hourly energy output, typically, and then calculates the cost of energy. So, we're really sort of combining a lot of engineering with a lot of finance, and that leads to some really exciting capabilities, but also leads to some interesting challenges, which we'll talk about as we go through this.

And so, really, we're sort of combining in broad strokes detailed performance models and detailed cash flow finance model, and real [inaudible] models, and then reasonable default values for each technology and target market. Next slide, please.

So model solar, and by "solar," we mean PV and CSP and for concentrated solar power right now, we have performance models for troughs, towers, distilling, and we have sort of a generic optical model which is a little more of an R&D tool, and then wind and geothermal are new sort of recent additions and, with that, you know, one of the things you can do with SAM is – and part of the real justification behind building SAM is that a lot of times a researcher at a national lab does a whole lot of work, comes up with a great algorithm, and writes it up in a nice paper and goes to a conference and reports on it, and then it goes on to a bookshelf, meaning that industry has to then find that bookshelf, get that algorithm, implement it probably in Excel, etc., and then how do you check it, how do you validate it, how do you work with National Labs to get the data you need out of the algorithm, etc.? And so we're trying to cross that bridge for people, both for the R&D community and the industry.

And so once you've got SAM, one of the things you can do, that people do a lot, is really evaluate and compare options. So, a lot of today's conversation has been about whether or not you have the right number. A lot of our conversations are about we think we have the best numbers we can get, and then how do they compare with you implement such and such change, either to the system itself, or to the finances, or to the cost. And, in the end, you can get to LCOE impacts, MPV impacts, payback, and perform parametric and uncertainty now since we have a lot of what if sort of capabilities, and we do a lot of graphing and tables which you'll see in a few minutes. Next, please.

So, again, we have PV and, contrary to solar power, I mentioned trough towers and distilling, one thing I didn’t mention is we have some limited capabilities with CPV, Concentrating PV, which, kind of depending on who you are, falls into one of those two buckets, and next year we’re going to be trying to work on more detailed modeling of CPV systems. Solar water heating, we have a number of capabilities in there, mostly residential and commercial scale solar water heating. We aren’t really talking about major industrial scale analysis.

Wind turbines and farms, we have three basic modes in the wind area, one is something that the research team at NREL uses called the Wind Turbine Design Model, which allows you to do tradeoffs between costs and longer, say, blade length and the resulting cost, and that ties directly to a detailed Excel cost model that NREL developed. And we have an hourly small scale wind model with a small scale wind turbine library, performance library with power curves, and we just released a new version utility scale hourly wind model, as well, and we can talk more about that if people have questions.

Moving to geothermal, we’ve worked with researchers at Idaho National Lab and DOE to implement a spreadsheet model called GETEM into SAM, which actually does a monthly calculation for 30 years of either hydrothermal or geothermal systems, and then, additionally, we’ve been doing – lately, we just released probably a less widely usable model, but something called Co-Production where you have low temperature hydrothermal resource mixed with oil and gas wells. And then, on the market side, we really try to get at everyone, and, again, this comes out of our history as a solar model because PV obviously competes in the residential, commercial, and utility scale markets, and each of those markets has unique assumptions and unique needs that we tackle all three of those markets when they’re appropriate. Obviously, geothermal power plants aren’t appropriate at the residential and commercial scale, and likewise most CSP is not appropriate at anything but utility scale. Installation operating costs, cost is a big piece of what we have, incentives is a big part of what we do, obviously it’s very important for renewables, and then, recently, we’ve really been working a lot on utility rates as one of our other key features and we at NREL have a public utility rate database which we are continuing to develop and hoping that utility industry also contributes rates that are machine readable and quantitative in nature, so we can access those, but it’s particularly important for residential and commercial scale PV, solar, water heating, and small scale wind. The key output, as I mentioned, our LCOE payback, MPV, cash flow, and debt kind of on the financial side, and obviously on the production side, the key outputs are really the total energy production, the capacity factor, the annual energy production. Next slide, please.

Background – we started working on SAM in 2004, again, exclusively for the DOE Solar Program. It originally started as an internal planning tool for DOE, they had a lot of sort of apples and oranges analysis coming at them, depending on which technology they were looking at, so inconsistent assumptions, inconsistent cost analysis, and they wanted a common platform to look at, how best to invest.

MR. RHYNE: Can you hold on a second, Nate? We lost audio here in the room. We're going to reconnect.

MR. ALVARADO: Hi, Nate. I think we lost you for a moment.

MR. RHYNE: There we go.

MR. BLAIR: Oh, sorry. I haven't moved, I promise. Are we back on?

MR. ALVARADO: Yeah, I think we're back on and I think you were just talking about really just starting your background slide.

MR. BLAIR: Oh, okay, thank you. This has been jointly developed by DOE, we have a team at NREL, we also work closely with Sandia National Labs, and what I was saying is that, back in 2004, the tool was originally designed as an R&D planning tool for DOE to help them have consistency across all the solar programs, and really provide that to them, and then in the interim, we've added these other goals of kind of leveraging what the labs are doing in a platform that industry can readily use. Next slide. Thank you.

We also work with a number of other groups, including the CEC, I'll point out, and the CEC has a PV model and a PV Module Library that we leverage in SAM, and they also work with the University of Wisconsin, as do we, for PV Modeling. We work with the University of Wisconsin also to help evolve our CST Models, many of which we've had developed for SAM, specifically, because they didn't exist, or didn't exist in the detail and formats that we wanted. I mentioned that we work closely with Sandia and we use a number of their models, and then we've worked with a number of groups. Most recently, Deacon Harbor Financial and, Mike, who just spoke, and our team, have worked very hard on the new version and detailed project finance models that are now in SAM. Next slide, please.

So, who is SAM used? We've had – I think that number is actually a little low now, we've had about 25,000 downloads by individual email addresses, we don't track all the individuals, but primarily from manufacturing firms, engineering firms, consultants, energy developers, venture capitalists, policy analysts, and it should say utilities, also, on that list. We've got a number of primary uses and these come from user surveys that we've done, feasibility studies, benchmarking for other models, often kind of private non-public models that people want to kind of benchmark against. We've got a number of R&D activities, both within NREL, and at universities and engineering firms looking at various engineering and finance factors, plant acceptance testing for parabolic trough systems, it's more of an issue so far in Spain, but as more CSP systems get built in the U.S., they have the nice neutral third-party model that most people can't agree upon. And then, as I said, sort of the very initial use of SAM was by the DOE to really look at technology research opportunities and grant proposals. When we turn in our plans to the Department of Energy, they often will ask, "Well, what does this do? If we do this research, what does this do to the LCOE of trough technology, for example?" And you say, "Well, I've run

Sam and I think if we do this research and we get this improvement in performance or capacity factors, we'll get this reduction in LCOE." Next slide, please.

So, again, in sort of half the model, it's all about predicting the system energy output, as the annual scale monthly scale and hourly scale, and we have these automatic graphing and outputs that are available within SAM to look at all this information. In some sense, when you're doing a detailed hourly model of a complex system, you can be hit by sort of information overload, unfortunately. So that's about – and a lot of people just use SAM for the engineering aspects. Next slide, please.

And then what we can do with SAM is look at Parametrics, so in this case we have a parametric around the orientation, across the bottom, and then across different locations, as you see by the three graphs, and all of this is handled automatically without SAM, if you'll just push the green GO button. You'll see, actually, this is looking at the optimal array tilt and azimuth angles for a small residential PV system. You'll see that almost none of them have – I guess Arizona is pretty close to zero, pointing straight south, but in the other two cases, Boulder and Los Angeles, you don't necessarily want to point your PV system straight south. For Boulder, you want to orient it slightly eastward because, in the summer, you have afternoon thunderstorms over the mountains pretty systematically and, then, in Los Angeles, you want to orient the array slightly westward to minimize the impacts of morning fog, so there are some interesting things. For Phoenix, there is nothing going on in Phoenix, so pretty much straight south. Next slide, please.

And then this is some of the work that gets done in looking at box impacts. This is for a Power Tower example with six hours of storage. If you decrease the tower height by 15 meters, that decrease the installation cost by 2.5 percent, which you can see in the upper left box. And what’s the impact of that on the LCOE? And it reduces the LCOE by four percent, so obviously these impacts are non-linear and this is the type of parametric analysis that you can look at very quickly in SAM. Next slide, please.

And then we do a lot with uncertainty analysis and it’s kind of an area where we’re growing, now that people feel more confident on their kind of general LCOE numbers, the next question is, well, what’s the uncertainty around all these LCOE values. And so, in SAM, you can do what we call the tornado analysis, their sensitivity analysis, and this shows the sensitivity analysis, and this shows the LCOEs most sensitive to collector cost, for example, in this example. And then, in the lower right corner, you can see the outputs from our Monte Carlo-type analysis, and again here you can input values and distributions around any of the input values, both engineering inputs and financial inputs, and look at the impact on the LCOE in terms of the spread of LCOEs across as a result of all the distribution. Next slide, please.

So this slide gets a little bit busy, but I sort of threw it in just to sort of show how things are broken up. We basically in the middle, we have this circle called SAMSIM, and that's really the core of what SAM is, that's where the hourly simulation happens, that's where all the cash flow analysis happens. From that, you can access just the SAMSIN work and then, around that is all of the SAM interface and, so, on the left side are all the inputs, finance, cost, tax credits, site location, and whether component parameters, simulation configuration, and then on the right are all the different outputs which we've spoken about and links to – we have a separate tool that really does the hourly data viewing, at least at this point. We can interact with Excel quite a bit, both in terms of outputting the outputs to Excel or, also, interacting between inputs in Excel, and we'll probably go into that right now. But I think what the message I wanted to convey with this slide was to say that there is a lot going on and a lot is required, and I think that's why our default values are so important that we use. We can talk more about that in discussion, but I think that's a critical piece. Next slide, please.

Extending SAM – you can use SAM through the interface, or you can use it behind Excel or behind Matlab, you can script the use of SAM and so that's where you just call indirectly to SAM, and the SAM interface will actually output all the necessary code that you need to run a particular example, in either VBA, Matlab, Python, or C. And I think this is really a helpful way, not everybody wants to do their analysis within the SAM interface, and this allows them to do most of their analysis in Excel and just call out to SAM as needed. Secondly, we have a scripting language within SAM, so if you are doing something our research teams at NREL often will run 1,200 weather files for all the U.S. at various tilts and azimuth to look at a whole suite of PV possibilities for the country, and so you don't want to do that one at a time, obviously, and so our scripting language is helpful for that. Next slide, please.

And this is just a quick example of using our scripted language. We've got a request, I think it was from BOE, to look at 30 GSA buildings with PV and try to roughly calculate the LCOE in the annual system output. And we had some basic numbers in terms of the size of the system and location of the system, and instead of running all these separately, which we could have also done, but that would have been a little bit error prone, there was a short script written, it's mostly on the right-hand side there, which ticks off the weather location, the D rate, the tilt cost, and the type of module, and runs that for each of those locations at once. Next slide, please.

So how do you get SAM? We have a website at www.nrel.gov/analysis/SAM, and it's free to download, all we ask for is your credit card number – just kidding – but we do ask just for your name and your email address so that we can let you know if we find – if we issue updates, as we did last week, or if we have some bugs that have been found, or we also use that email list to do occasional surveys of the users and talk about what we think the next things to add are, and get that feedback. Next slide.

So a few more questions in the guidance from the workshop that weren’t – that I wasn’t sure I had addressed in the slides, one of which was do you add environmental implications and benefits. The answer is really not at this time, they could be calculated, obviously, outside the model and added in. We’ve had a few discussions with user groups that want to look at calculating the avoided carbon by location, so you’d have to figure out what is the source of the electricity in that location, what’s the mix, and what are you offsetting, and obviously to do that hour by hour, so that, you know, wind which blows more at night than PV during the day, offsets a different mix of generators than PV does. So far, we haven’t moved forward on that, but that might happen in the future.

What’s the source of the cost driver, the escalation assumptions, and generation characterization? So, as I think everybody has mentioned, this is a difficult area to get information, we generally – in the early days we worked with NREL experts and BOE experts to come up with default values that we thought were appropriate. I think that the general Federal cost modeling has gotten more robust and, especially for PV and CSP, we now go to NREL experts, but they often have a recently published document, or in conjunction with, say, Black and Veatch, and Ryan’s group, who spoke earlier, we can get these default values. And we update them with each release which is usually about twice annually, so we usually do a release sort of in the springtime which we did just last week, and then one sort of at the end of this fiscal year, so September, October time frame. We don’t include anything about future projections. You can obviously use SAM to do what’s today and what does the future look like, especially in separate cases, but we don’t have any default values for the future. And, well, real-world LCOEs are subject to a variety of impacts. The comparison efforts to date have shown good agreement between SAM and expected or current known LCOEs in the marketplace. Obviously, published documents that we use get a lot of our cost data, and some of our performance data, those often will calculate an LCOE and we’ll compare it to that. It is often difficult to get cost data, especially as you get to utility scale systems, but we have a number of initiatives at NREL to look at residential and commercial scale PV costs and costs at other times and other periods – I’m sorry, further technology – sorry, my computer was giving me a message. Next slide, please.

And here, I don’t know if you can give me control, I have SAM up on my laptop, is that possible?

I think you were trying that with Mike and it didn't work, but….

MR. RHYNE: Yeah, I don't think we're going to be able to do that today.

MR. BLAIR: Oh, okay.

MR. RHYNE: And that's fine, you know, I really appreciate what you've presented thus far. I think we're more interested in the thinking behind the model than the specific functionality of the model, itself, today.

MR. BLAIR: Okay, sure. Great. Are there any questions?

MR. RHYNE: Any questions here in the room?

MR. KUBASSEK: Hi, this is Jason Kubassek with Edison. My question is if you've done any benchmarking between the hourly data and using an annual assumption, which we typically use here. And is it more – what's the added value of doing an hourly simulation vs. making an annual assumption?

MR. BLAIR: Well, I think there's a couple of values and we have done benchmarking, we often will compare the sort of annual output and the annual capacity factor against other published sources and we get good agreement, obviously, the trick is in the input files and the D rates and whatever else you want to do to tweak the model, but that's where I think our default values are representative of typical systems, but one of the reasons that we do hourly modeling is that, from the very beginning, people wanted to look at -– especially for CSP -- you know the impact of time of day dispatch and time of day production, and so if you can, say you're in Phoenix, if you can produce power later in the evening when it's more valuable and when the air-conditioning load is the highest, that's going to get you significantly higher value. Obviously, the LTOE is going to be the same, but your net present value will change significantly if you can get into that kind of late afternoon peak period. So that's one aspect. The other aspect is that, for hourly modeling at the residential and commercial scale, if you're looking at trying to think about different utility rates or different utility or potential utility rates, even, you know, obviously you need to know when during the day the system is producing power.

MR. MCCANN: This is Richard McCann with Aspen. Just to follow-up on that, so you had this chart that showed the configuration of the optimized design parameters, I think it is Chart 9, that shows the orientation of these optimal solar array. Does this optimize for energy output, or – it sounded like it optimized for energy output, but can you optimize for value, then? Is that what you're seeing within the model?

MR. BLAIR: Yeah, I think it says that you can optimize design parameters and, in this case, what it's really doing is just a parametric in order to get that graph. We do have a min-max kind of optimization and you can minimize LCOE, or maximize MPV, and let various inputs adjust. We find that that's useful for relatively simple analyses; when it gets to be more complex, you'd probably want to start doing sensitivity runs and some more kind of type of parametric analysis, instead. But, you can optimize on the MPV. Does that answer your question?

MR. RHYNE: Yeah, I think so, he's shaking his head. So, this is Ivan Rhyne again. So, you walked through some really interesting functionalities and, you know, presented the overall approach. I'm curious if there's anything in particular, any areas, where you would caution end users against not attempting to use your model for anything, specifically?

MR. BLAIR: Oh, I think, you know, as I was saying before, we do our best with the default values, but obviously the – well, U.S. national averages, and so I think one of the problems, one of the areas we get into as we see analyses done either at NREL or by non-NREL people that said, “Well, we used SAM and this is what SAM told us the answer is.” And we say, “Well, okay, that’s fine,” you really need to be thinking hard about your inputs and your input values, so I think that’s fine, I think we don’t want people to be doing – I think SAM is great with our new finance model, it gets quite a bit further down the road in terms of being able to provide robust outputs for various financial structures, but, again, at some point obviously before you’re going to want to build a system, you’re going to want to go to an actual financial consultant and financial officer to really do some detailed performance for you.

MR. RHYNE: And so then, as a follow-up on that, I’m kind of inferring from your statement that this is almost better used as a comparative model between types, rather than an objective, here is what the number – here is what the cost is. Would that be a fair statement?

MR. BLAIR: I think that’s right. I think, 1) we require kind of a higher level of expertise from the user base that, you know, we are providing default values so that, if you really – the goal of those is, really, if you care about the engineering analysis, but you want to get to an LCOE, the numbers in the financial input pages are going to be appropriate enough that you're not out in left field, but if you're really trying to get to, "Hey, here's the final LTOE for this precise location," you really need to be able to look at all those numbers and say, "Yeah, I feel comfortable with all those numbers," rather than saying, "This is what SAM has for a default, so it must be the best number." And I think you're right in saying that we see this tool as being one where you're comparing between options, and often those options are fairly detailed. We do have people that are using it and saying, "Hey, this is the number for this system and this location," but those people – we expect a level of both engineering and, I guess, financial capabilities. I think out of the box it's more appropriate for comparisons between system choice options.

MR. RHYNE: Okay, and then just a final question. Obviously, the SAM model is focused on renewables, started out with solar, and it has been expanded since then. Where you and your organization may occasionally have to look at non-renewables, do you have fallbacks in terms of cost estimates, places that you go for that information? Or kind of concerns about models that attempt to compare renewable to non-renewable technologies?

MR. BLAIR: Yeah, I actually was one of the modelers that worked on that 20 percent wind by 2030. I’m sure Ryan remembers, as well. And, again, here the question is apples and oranges, are you going to one source for your renewable cost numbers and performance numbers, and a different source for your conventional numbers? And are they taking into account sort of the same things? Two comments, one is that we do actually have a generic fossil model in SAM which allows you to either calculate just using an annual production or capacity factor, and availability numbers, and then you can use any of the detailed SAM financial models along with it. We do have that capability because we actually got feedback from users that they wanted to compare what they’re getting for solar systems to what they want to – they want to compare it to gas plants, for example, using the same financial assumptions to see how they all compare it, but I think that typically we will go to a variety of sources. We actually built something called a cost data page and NREL, which is fairly high level and fairly simple, based on publicly available cost data, and I sympathize with everybody else on getting these numbers, especially for technologies like PV which is very fast moving in terms of cost. But we often will go to the EIA, you know, and Black and Veatch, and other organizations to get conventional cost data.

MR. RHYNE: Okay, thank you very much. Are there any questions from online participants? No, it doesn't sound like it. Any other last questions from within the room? No, okay, thank you very much, Nate, for your participation.

MR. BLAIR: Thank you.

MR. RHYNE: And so I'm expecting you to hang around for our panel discussion, but first we have one last presentation. Our next presentation is from Justin Kubassek from Southern California Edison.

MR. SILSBEE: Ivan, while Justin is getting set up, I would like to make a few introductory comments if I could.

MR. RHYNE: Good.

MR. SILSBEE: I'm Carl Silsbee from California Edison. I manage Edison's participation in the IEPR proceeding at this Commission, and also our participation in the CPUC's Long Term Procurement Plan proceeding. Justin and I are in a group at Edison that is responsible for resource planning issues. And, of course, the Cost of Generation Model has a number of applications in that area, so we're very familiar with it. At the outside, I would like to express my thanks and appreciation to CEC staff for hosting this workshop.

I'm hopeful that the dialogue will help us improve some of the uses of that model, and certainly to improve our understanding of how it's used in a variety of resource planning forums. As you know, the Cost of Generation Model is widely referenced in resource planning proceedings dealing with choosing resource strategies and, as such, it does really get to the issue of comparing the cost of different technologies.

As you heard this morning from a number of the presenters, levelized cost of energy modeling fall short in a number of key areas in providing effective rank ordering. I also find that people who just simply use levelized cost of energy modeling without understanding the limitations, oftentimes come into regulatory proceedings with very simplistic views of how different technologies truly compare in cost. And so I think improvement in the sophistication of everybody's understanding will be something that is very helpful, and I would hope that the CEC would take a leadership role in that area.

Justin is going to go into some details of what we see as some of the limitations of the levelized cost of energy modeling as currently implemented, and make some suggestions of things that it can modify in the model. Our hope is that we can make incremental suggestions and stay within the existing framework that the Commission has established for the Cost of Generation Model.

And then, a couple of final comments. Although the scope of this workshop is not directed to the data inputs, I'd like to express general agreement with Joel's comment that the process by which the CEC uses to develop the data inputs in general produces reasonable results. We are in the course of developing our own estimates for technology cost for many of the resources that go into the model, and we'll be very happy to share that information with you as the CEC goes forward to update the model next year.

Finally, I'd like to make a point that Edison strongly supports technology-neutral all source procurement, and so what we see as an advantage of this kind of comparative cost analysis being is to inform generation and transmission planning efforts, and to influence policy direction. We don't see this kind of modeling as directed to picking winners or losers, we think that is more appropriately done in a competitive setting. So, again, thank you for all the work that you've put in over the years on the cost of energy modeling and I'll turn it over to Justin.

MR. KUBASSEK: All right, thanks everyone for sticking around for these presentations. Also, I like the name that Ivin picked for my presentation better than mine, it sounds much more interesting. But anyway, so my presentation today will just be talking about the Cost of Generation Report. We don’t have our own model here that I’ll be presenting.

But, as we know, the CEC puts together a report that outlines for a number of different resources, what’s called a Levelized Cost Estimate, which is essentially just the lifecycle cost divided by annual energy production. And according to the CEC’s website, these costs provide a basis for comparing the total cost of one power plant against another. What we find is that the way in which the data is presented and what’s included in the analysis actually makes that very difficult. And we find that the result, as presented in the report, and as presented by the model, actually lead to some erroneous conclusions about the relative costs of different generating technologies.

What I’ll be presenting here is a framework for calculating a levelized cost for different technologies, intermittent and dispatchable technologies, that allow for a meaningful comparison of the two numbers. There are two reasons why the CEC’s report and why levelized cost estimates, in general, tend to produce erroneous conclusions, especially when it comes to intermittent resources and dispatchable resources. The first is that these levelized cost models only calculate explicit accounting costs, the cost of putting the steel in the ground, combined with some assumptions about return on equity and price of energy in a contract, so that you get total lifecycle cost. Specifically, the Cost of Generation Model doesn't capture differences in economic life, capacity, dependability, time of delivery, flexibility, or integration requirements. Second, as was alluded to in the E3 presentation, the data is presented on a dollar per megawatt hour basis, which includes an assumption about the capacity factor that greatly impacts the result. This is most notable with the CT, but it impacts even comparing a CCGT to solar or wind.

At the end of the presentation, we'll have a framework and I'll also present the methodology we did to come up with some actual estimates for these numbers, that we think is meaningful and that it is more in line with what our expectations are.

This is a graph just pulled from the latest report, and the story, we've talked about this before, it suggests that solar and CT are just completely out of money and we should never build these things, but as we know, they serve a different purpose and, with the case of the CT, it's really just the fact that it's an all in dollar per megawatt hour metric. But, in addition, we're comparing a CC with a 70 percent capacity factor to solar and wind, which are producing actually much less energy. So, in the case here, the CEC is actually incurring these additional fuel costs and bond costs, and presumably it's in the money, it's running, and they're gaining some revenue for it, but that's not captured here, and that's fine, but there's a mismatch there, as well. Ultimately, the existing framework cannot really show any cost-effectiveness or make any reasonable conclusions because, 1) not all cost elements are included, we're not including any economic or implicit costs, and resources with different capacity factors are being compared on this dollar per megawatt hour metric.

For the rest of the presentation, I'll actually propose a methodology for correcting for the five items that I laid out, and they're all pretty simple, so the first is we need to include replacement energy and capacity costs. This will address equalizing across different economic lives. The second is include firming costs, which will be based on resources and then qualifying capacity. The third will be include a nondispatchability cost penalty for must take resources, which will address time of delivery, flexibility. The fourth will include integration costs for intermittent resources, and then the fifth will be compare resources on an equal capacity factor basis, using a screening curve.

So, I'll start off with comparing across equal economic lives. To illustrate this, we'll compare two resources with the same levelized real value, or real economic carrying charge. Basically, what that means is that, instead of holding constant – okay, so in the levelized nominal framework, you calculate the lifecycle cost, and then convert that into a payment that stays constant in nominal terms. What we've done here is convert that into a payment that stays constant in real terms. So, this value here for each of these resources is the same, and then we escalate that over the life, and this is the nominal value here. This line here is just sort of illustrative of what the levelized nominal value would be for each of these resources, and what we can see is that resource 1 appears to be more cost-effective. In reality, a decision-maker should be indifferent between these two resources because in Year 21, he's going to have to replace resource 1. And when he or she does so, the value is going to be the same as resource 2, and so, really, it’s kind of a misleading conclusion here simply because resource 1 is avoiding these additional costs, these carrying charges. There are two solutions to this, one is calculate some generic replacement energy and capacity costs, and just include that on all resources that have a shorter life than sort of, I guess, would be the longest lived asset in the analysis. The second would be to assume the same technology is replaced again, in which case you can just calculate a real economic carrying charge and compare on that basis. And that’s what we do in our analysis. And trudging back, on a real economic carrying charge basis, these two resources have the same value, and therefore you kind of avoid that conclusion.

The second piece here is we need to include the cost of procuring additional capacity. Traditional LCOE analyses have basically just kind of made the implicit assumption that a kilowatt of one resource is the same as another, so you’re not going to be incurring any additional capacity cost when you’re getting – you’re deciding whether to build a CT or a CCGT, both are providing the same capacity. So, really, it’s irrelevant and you don’t really need to consider that. With intermittent resources, it’s not necessarily the case, therefore, when making a decision between an intermittent resource at a higher net qualifying capacity, a decision-maker needs to consider what that additional cost will be if he chooses to purchase or build the resource that has the lower net qualifying capacity. To estimate that here, we use net qualifying capacity numbers that the CAISO publishes, and that's kind of a best estimate, it's based on historical information, but we make the assumption that net qualifying capacity is a reasonable assumption, or estimate of what the true dependable capacity is, or value of that resource to system reliability. Then, we calculate it with the additional capacity cost using the fixed dollar per kilowatt year levelized cost from the CEC's Cost of Generation Report. CTs are typically used as a proxy for what additional capacity costs are. And now, once we make this adjustment, we've included – we're comparing these two resources on an equal capacity basis. In the costs that we're seeing, we're getting the same capacity value.

The third item here is capturing the value of dispatchability, the value of being able to control where you're on or when you're off. Must Take Resources don't have the ability to optimize their dispatch against market prices, therefore, when considering a resource where you have that ability to one where you do not, you have to consider the interaction between the expected generation profile of the Must Take resource to your projected market prices. The differential between what a must take resource's average price would be if they could optimize for their given capacity factor vs. the average market price that they actually face is an opportunity cost to choosing that particular resource to serve energy.

Our methodology for us to maybe miss was to take an implied heat curve from SCE's default load aggregation point price for 2010, and then we used the levelized gas price forecast from the CEC model and had basically created then a forecasted heat rate curve and used some historical generation profiles that we had, so – and to implement this, we need some estimate of both market prices and generation, but I think some sources are publicly available.

What I have here is just an example monthly profile from a wind resource that we had access to data to in SCE's portfolio. This story here is one that I think we're all pretty familiar with. Generation from wind resource is pretty volatile, and that operationally requires additional regulation, ramping and following services. That work is ongoing, it's certainly not linear, it's dependent upon the technology, the location, a wide number of things. So we include a $15.00 per megawatt hour estimate, and that is kind of just there to show the implications of this. So, again, it's an additional cost to whatever a decision maker needs to consider.

Here are the results of the analysis I did and this is posted on the CEC's website. I just took the CEC's base numbers, had a few sheets of extra calculations, and then I'm holding capacity factor constant, so the CCGT and wind are both producing the same amount of energy. What we find here is that the differential between wind and solar has diminished. Also, we find that, for the same capacity factor, wind is actually slightly a bit more expensive than a CCGT, primarily due to this hidden capacity cost. It's not reflected in the cost of capital, or in the cost of actually constructing the resource. Also, it's interesting that the way this analysis was done, on a dollar per megawatt hour basis, wind actually doesn't have as much of an opportunity cost of energy as solar, which is kind of surprising since you think solar produces more on peak. I think that largely has to do with just the fact that wind is producing – has 37 percent capacity factor, so I think it kind of outweighs it into this analysis, and it was 2000 – looking at historical data, so….

So comparing on the dollar per megawatt hour basis is perfectly acceptable if you are holding capacity factor constant, but it’s a little bit clunky and you kind of have to do it for each resource. So what we propose here is actually developing a screening curve where dollar per kilowatt year is on the Y axis, and then we have capacity factor on the X axis. These screening curves just kind of produce a nice straight line, so it’s visually pleasing and easier to kind of interpret. And intermittent resources are just point estimates here.

As you can see here, the analysis really is more reflective of the other underlying economics, which is that, as a peaking resource, CTs actually do make sense if you’re comparing it to building a CCGT or coal. So that conclusion that CTs don’t make sense is not here, as you can see why. Second, we see that the conclusions are exactly the same as the dollar per megawatt hour conclusion, so there are really just two ways of looking at the same value, which we know, but just to illustrate that, the conclusions are the same. And we’re comparing it to a CCGT on an equal energy basis.

So, in conclusion, we would recommend kind of including these additional costs as implicit or economic costs: one is, first and foremost, equalize dependable capacity across resources, this has the biggest impact on the analysis because, although wind has very cheap installed cost and capital cost, it simultaneously has a low capacity value and there's an interaction effect there; the second is incorporate the value of dispatchability, and that can be thought of as an opportunity cost, or being a must take profile; the third is incorporate an estimate of integration costs in some way; the fourth, compare resources across equivalent timeframes; and then, finally, compare resources using a screening curve. And that's the end of the slide show.

MR. RHYNE: Justin, before you move on to the rest, I want to clarify, you made a proposal of including a $15.00 additional charge?

MR. KUBASSEK: Uh huh.

MR. RHYNE: It was the integration – so that was $15.00 per –

MR. KUBASSEK: Megawatt hour.

MR. RHYNE: Megawatt or megawatt hour.

MR. KUBASSEK: I would hate to come up here and say anything that is – I think this is here just as illustrative purposes, so –

MR. RHYNE: And I recognize that. What I'm interested in, though, if I take that as illustrative, where we're trying to go is to understand, well, how should this be done. So, do you have or could you propose a method for getting to number that is not illustrative, that is actually useful with regard to this activity?

MR. KUBASSEK: I think Carl will probably say the same thing I'll say, but –

MR. SILSBEE: We've seen estimates in other areas of the country, maybe $10.00 to $15.00, there are a variety of studies out there. Unfortunately, the numbers are very widely – because I think they are very site specific. In the Long Term Procurement Plan Proceeding, we think we may get some metrics as to the cost of moving from where we are today to 33 percent in terms of renewable integration, and that may be helpful to us to get a little more context specific California type number for renewable integration. One of the challenges, though, is we have some level of capability today to handle additional need for renewable integration. So if you're measuring from, let's say, 20 to 33 percent, you're going to eat up free capacity for renewable integration, where you then start having to accrue the costs, so I think, even best outcome out of the LTPP, it will still be a bit fuzzy for us now and it’s something that will have to get refined over time.

MR. RHYNE: Right, so I think that puts us in a quandary, I mean, recognizing that there may be some additional or marginal cost associated with renewable integration isn’t quite the same as being able to put a dollar value to it in terms of adding it into a cost model such as ours, and so, while we can all kind of nod our heads in a theoretical sense and go, “Yeah, there’s probably something there,” we – the CEC hosted a workshop, I think, last week or the week before where the ISO presented the results of their 33 percent Integration Study and indicated that there’s very little need, in fact, from their point of view at this point for additional integration resources. That’s not to say that it’s zero or zero cost, but simply taking an illustrative number of $15.00 doesn’t necessarily get us to where we should be going with what to integrate into this model.

MR. SILSBEE: I agree with that. There was some analysis presented, I believe it was by Lawrence Berkeley Labs in the LTPP proceeding at the request of the Commission to look at some of these issues, and they cited a variety of sources in the literature for estimates on renewable integration costs.

MR. RHYNE: So, I’m hoping that you’ll provide written comments that, at the very least, point to that so that we can get that into our own record, as well. Thank you.

MR. KUBASSEK: And actually, I'm glad you brought me back to this slide here. So, two things that I missed, first is we included some GHG costs just into the model to cover that area, as well. We used the Synapse mid case and just stuck that into your model, so I wanted to point that out. Also, this analysis here just uses the CEC's assumed 20-year life, and SCE recommends a 30-year life consistent with industry norms for depreciating CCGTS.

MR. KLEIN: Joel Klein. That's just for combined cycles, not for combustion turbines – a 30-year life you're –

MR. SILSBEE: I think we see CTs as having a 30-year economic life, as well.

MR. RHYNE: Okay. So what -- I'm sorry, that raises a different question -– so what does that do in terms of biasing the numbers for or against any one particular technology if you could pick a 30-year lifespan? What about technologies that have a 50-year lifespan or longer? Is there actually a number we should be looking out beyond 20 years and, say, looking at two generations, or two iterations? I'm asking the question because the lifespan kind of normalization that you're talking about seems to be targeted on the lifespan of a combined cycle.

MR. KUBASSEK: Well, actually, using a real economic carrying charge actually will adjust everything to an equal or a comparable value; it essentially, basically says if you assume, if you use the real economic carrying charge, then however many times you assume that that resource will replace itself, it doesn't affect the fundamental value. So, using that approach, you can compare a 30-year life assay to a 20, to a 40, to a 50, because it assumes that you're going to replace that asset with itself, and that won't change the starting value.

MR. RHYNE: Okay, thank you.

MR. KLEIN: I have another question.

MR. KUBASSEK: Yes.

MR. KLEIN: Joel Klein. Putting aside for the moment the GHG and the different lives, you know, the life adjustment –

MR. KUBASSEK: Uh huh.

MR. KLEIN: -- and I say put those aside because those are costs to the builder, to the developer, okay? The others seem like they're not cost of the developer, they're cost to the system, which means we've got to ask the question, what is this Cost of Generation Model proposing?

MR. KUBASSEK: Well, two things. One is it’s not necessarily cost to the system, per se, as cost to, for example, the – we don’t know who is going to have to pay integration costs. There’s talk about putting that back on to wind resources and BPA rate proceeding, if I’m correct there?

MR. SILSBEE: I heard about that, but I think it makes some sense to us, certainly, to have the integration costs paid directly by the entity that causes those costs, so that you align the economic incentive to most inexpensively resolve the integration problems.

MR. KUBASSEK: For capacity, the IOU has to meet an RA requirement and, so, when choosing resources, the IOU will have to face, or the load will have to face the additional capacity costs, so these are – this is a perspective of the decision makers, so if we’re providing this data as to decision makers, then we should include the implicit or economic cost just as much as we include the accounting cost of the asset.

MR. SILSBEE: If I can add to that, and I suppose we’re moving on to kind of the panel discussion here with this –

MR. KLEIN: Yeah, maybe this could be deferred to the panel, I don’t know, don’t let me interrupt you.

MR. SILSBEE: You know, Ivin put out an objective at the beginning of the session this morning to develop the cost of the generator, and so I started thinking about that as we were going through the sessions this morning and thinking about, well, from whose perspective are these costs relevant, and is there a difference between the costs a developer faces that, you know, would be internalized with the developer, and the cost that the ratepayers or taxpayers who ultimately bear the burden of these costs would face? And as I thought about it, I reached a conclusion that maybe there isn’t much of a difference here because, even for a developer, they’re not only concerned with the direct costs they face, but they’re going to have to enter into some sort of a solicitation where they’re competing against other kinds of renewable resources, and when they do so, the utilities that are evaluating those bids are going to do so on a least cost benefit basis, and if they have indirect costs associated with their project that make them less attractive, or more attractive, then that factors into which technology is likely to be the winner. So, I think in either case, whether your perspective is as a developer, or a consumer of the power, it's important to get these indirect costs in the calculation.

MR. KLEIN: But I guess my final reservation – not to take away from what you said, but I guess my final reservation would be that, like Ivin was saying earlier about integration, it leaves us with somewhat ambiguous numbers, that would be my final reservation.

MR. RHYNE: Okay, it sounds like we have a question online. We can go ahead and unmute the person.

MR. MILLER: Yeah, hi. This is David Miller from the Center for Energy Efficiency and Renewable Technologies. Can you hear me?

MR. RHYNE: Yes, we can. Thank you.

MR. MILLER: Great. Thanks. I think it's a great talk, in part because it does actually expose what some of the underlying costs are. I think the question of who pays for those is much different.

MR. RHYNE: Sorry, we're having a little bit of an issue with some folks.

MR. MILLER: Am I still on?

MR. RHYNE: Okay, yes, you are. Thank you, go ahead.

MR. MILLER: Okay, awesome, yeah, thanks. Okay, so my first point was that I think it's a great talk because you're actually exposing what some of the underlying costs are. I think the question of how those get paid for is a wholly separate question, which I’m not even sure this proceeding addresses. But my next question is actually more of a clarification. If you could go to the next slide, I didn’t quite follow your argument about how you were putting the wind and the CCGT on the same footing. If you could just go over that again, I would appreciate that.

MR. KUBASSEK: Okay, we’re – I guess by putting on the same footing, I simply mean we’re comparing them on an equal capacity factor basis, so if you go back to this slide, it’s a little less obvious, but a combined cycle is incurring a significant amount of variable cost here, which presumably have value to the system, otherwise we wouldn’t make the assumption that they’re running then. So I’m simply making the argument here that what we are doing is benchmarking these resources to their next best option, or conventional option, which is illustrated as this screening curve of best resources, or generic resources by capacity factor.

MR. MILLER: Okay, okay, I think I might have to contact you offline to get that there. Thank you.

MR. KUBASSEK: Sure.

MR. RHYNE: Okay, any other questions online?

MR. MENDEHLSOHN: Can you hear me?

MR. RHYNE: Yeah, we can hear you.

MR. MENDEHLSOHN: I’m interested in the possible duplication of costs looking at the opportunity cost category and the integration cost category –

MR. RHYNE: And can we get you to say your name and organization, quickly, sir?

MR. MENDELSOHN: Oh, sure, this is Mike Mendelsohn from NREL.

MR. RHYNE: Oh, thank you.

MR. MENDELSOHN: Sure. Have you thought about the possible overlap of those categories? And how do you know that they’re not overlapping?

MR. KUBASSEK: So you said the overlap between the opportunity cost and the integration costs?

MR. MENDELSOHN: And the integration, yeah.

MR. KUBASSEK: So, opportunity cost, just to make sure we’re – I mean, by opportunity cost, that’s referring to the dispatchability value, so the energy value from when you get to produce, when you’re producing on-peak, or off-peak? Or are you referring to the capacity adjustment?

MR. MENDELSOHN: Well, I guess all three because if you could produce whatever you want, then we wouldn’t have – yeah, I would think it would be so overlapped in opportunity cost and capacity adjustment, as well as opportunity costs with integration. It’s not perfectly clear that – if you could resolve all the integration issues, then you wouldn’t have an opportunity cost anymore.

MR. KUBASSEK: Well, I guess it depends on what resolving the integration cost means. I mean, if you can have a battery that turns all wind energy into a battery, and then the battery becomes like a CET, I guess presumably you could make the argument that you could then dispatch against market prices. But if you are just simply on an hourly basis turning your wind output into a Block E profile, you still would be producing primarily off-peak.

MR. MENDELSOHN: Okay, but the integration cost represents the cost of your spending reserve, would that be right?

MR. KUBASSEK: It would reflect the costs needed to operate the system on a day to day basis, and it should not – I can see the argument that some element of integration cost, if calculated inappropriately, could overlap with capacity adjustment, but fundamentally, it should not, it should only capture the cost, the additional cost needed to run the system on a day to day basis; whereas, the capacity adjustment is the cost of meeting a planning reserve requirement or meeting a generation peak load requirement.

MR. MENDELSOHN: Yeah, it’s hard to tell from just looking at your presentation. I mean, I think you need to spell out really clearly how each of those costs are calculated. I think that would help.

MR. KUBASSEK: Okay. Yeah, we do have, like I said, the spreadsheets online on the CEC docket, so you can take a look there at my exact methodology. Carl, did you –

MR. SILSBEE: I was just going to say, in the LTTP proceeding that’s ongoing at the Commission now, there is a Step 1 analysis that looks at the amount of ancillary service requirements in regulation up, regulation down, that is necessary on an hourly or seasonal basis to accommodate certain renewable build-outs, and those ancillary service specifications are then put into the Plexos modeling in Step 2 as constraint equations, and then the system is solved for the mix of resources that need to be committed, and to meet both energy capacity and ancillary service requirements. And then if there are constraint violations, then that results in adding additional renewable integrating resources to the modeling. That approach, I don’t believe, creates any overlap between the three components of cost. There is one implicit assumption which is to solve first for planning reserve market capacity, and then define renewable integration need as that which is in excess of the planning reserve.

MR. MCCANN: This is Richard McCann with Aspen, just following up a little bit on the opportunity costs and integration costs, it's not the question I was thinking of, but…, depending on your methodology, there could be some overlap between those two if you're using market prices rather than a proxy power plant cost, or market operations because there is some energy use in the integration costs, which then could roll over into your opportunity costs, so there could be some double counting that's going on there, but I can also see that there are probably ways of pulling that out from the LTTP in order to pull that -– or the ISO studies -- in order to adjust for that, and it's the same thing with the capacity adjustment and, of course, the LTTP studies are showing that we don't need any capacity past 2020, so you would be actually until 2020 at the earliest, so you would be probably taking a deferred investment in capacity adjustment sometime down the road in putting that into the model. But what I was thinking, there are a couple other elements in this adjustment in adapting this type of overlay that would be probably useful, as well, which is the RPS itself, it basically says that renewables have other values for environmental factors and for resource diversity, so those would be elements that you would want to put into this overlay, as well, and so you would have to try to figure out how to put that in, I think, into your cost model, as well. One of the things about this is that the Cost of Generation Model, the way it’s constructed now, it is essentially self-contained in that it doesn’t require inputs about other resources, about any other types of other resources, except for natural gas prices. And so, adding these other elements then bring in, okay, you need to add in system costs into the model and have those elements. And so that’s what makes this a bit more complicated and then you have to decide, okay, what are you trying to present? The idea of does this identify what the utilities are doing for least cost, best fit, well, then, that makes it – maybe it does make it a very useful tool if that’s what the utilities say this is what they’re using it for. And that may add transparency to that entire process in a way that actually makes it a very useful tool. So, just my thoughts on that.

MR. RHYNE: Okay, any other questions here in the room? Any other questions online? All right. So, I know, Justin, you had the spreadsheet here in the background, I know that it’s also available on our docket online and that we’ve got a panel discussion, I think we can go through, unless there was something specific you wanted to bring out of it.

MR. KUBASSEK: No, there’s nothing that I really want to –

MR. RHYNE: Okay, so I’m going to ask that we take about five minutes and, at 3:00, we’ll start our panel discussion. And then after the panel discussion, Al Alvarado will wrap up the day and we can all be on our way. So I’ll see you all in about five minutes.

(Break at 2:54 p.m.)

(Reconvene at 3:01 p.m.)

MR. RHYNE: All right, I’m going to ask everyone to go ahead and retake your seats. Our two presenters from earlier in the day are unmuted, so they can also participate in this panel discussion.

So the ground rules for the panel are relatively simple, these questions are not directed at anyone in particular, and I don’t expect the entire panel to go through and answer in order, right to left, or left to right, or anything like that; rather, this should be more freeform and my questions are meant to be conversation starters. Some of these conversations, we’re picking up from earlier in the day, and some of these conversations are going to be perhaps new and heading down different avenues. So, if any of our panelists want to respond, please feel free to do so, and you don't have to raise your hand, and then, as any of the audience either here in the room or online care to add to the discussion, or add their own questions to the discussion, please feel free to do so, I would just ask, as you either come to the podium or as you chime in online, that you state your name and your organization so we can get that for the record.

And so I've got a combination of questions here, some of which were kind of pre-developed and are in the agenda, some of which have kind of developed over the course of the conversation today. And so the first question is a broad question about this type of cost modeling. So, what's interesting is that, over the course of the day, we've really zeroed in on the idea that this is not simply cost estimation, and I don't think any of the tools themselves just estimate cost. They attempt to put cost in some context of value. Typically and traditionally, that value has been cost per unit of energy, energy being the key value metric. But as we've heard today, energy may not be the only value metric that needs to be addressed. There is cost per unit of capacity, cost per unit of ancillary services revenue, costs per any number of things.

And so I'm going to throw it first to the panel, what do you see as being the next evolution of kind of this cost estimation process for new generation resources? Should we be sticking with the cost per energy, in other words, the levelized cost of energy paradigm? Or, do we need to be adding something in terms of capacity? Or, does that require its own separate modeling activity?

MR. CUTTER: I'll take the first stab, this is Eric with E3. I think one simple step that would be a tremendous help, that has been touched on several times today, simply having dollar per kilowatt year in capacity separated for the fixed cost, and then there are various options for doing the levelized cost of energy for different capacity factors and any one of those would be useful. It seems challenging to get much beyond that. I guess I want to be cognizant of the role the CEC plays in developing at a policy level cost estimates for different technologies vs. the role the utilities and the CAISO and the CPUC are playing in developing portfolios of resources going forward. And if we're trying to address integration of a bunch of different LTPP scenarios with Plexos model runs, it seems like we don't want to try and reinvent that wheel here at the CEC, but the CEC can fill a really helpful role in the Cost of Gen Report already in having some validated reviewed cost estimates for different technologies. I would sort of be leery of trying to take on too much in the IEPR process that can be done better elsewhere.

MR. MENDELSOHN: Hi, this is Mike Mendelsohn from NREL.

MR. RHYNE: Go ahead.

MR. MENDELSOHN: Okay. I would argue that these LC models generally should be restricted to comparing very like resources. I think they’re good tools for quick analysis across PV technologies, for example, or wind resources, but because of the constraints that have been discussed today, I don’t think they’re good tools for looking across resources and, absent some sort of adjustment like SCE has tried to make, I think they need a big asterisk next to them.

MR. RHYNE: I’m sorry, did we lose you?

MR. MENDELSOHN: Oh, I’m not sure –

MR. RHYNE: You said “a big asterisk next,” and then it kind of faded out.

MR. MENDELSOHN: Next to the results of these models, that we should just be very careful in comparing results across technologies.

MR. KUBASSEK: I guess our issue with the asterisks is that not everyone reads them and the CEC is doing a great job here of trying to better their process and I think the feedback here is that the CEC can add a lot of value by putting the format of the data in ways that are harder to misconstrue, as well as putting in analysis that is taking it to the next level beyond what has been done. So, that’s just my caveat for asterisks.

MR. PLETKA: This is Ryan Pletka speaking. I mean, it needs to be clear that we’re talking about different products when you compare simple cycle and wind, it’s like going to the grocery store and comparing eggs and bread, and one of them is lower cost, but you really need both, right, to make an egg sandwich, I guess. So, just to be clear, these are different products and a table like this does sort of – obviously somebody is going to want to look at that and say, “Why would we ever put in these simple cycle things? That doesn’t make any sense at all.” So….

MR. KLEIN: Okay, I wanted to get back to Eric’s suggestion. I’m just trying to understand it.

MR. RHYNE: Can you use the microphone, Joel?

MR. KLEIN: If you look up on the wall there, Eric, you see I have one table of dollars per megawatt hour, and I don’t have it up there, but there’s a comparable table of dollars per kilowatt year, same table, different values. Okay, so the data as I know it, it's all there someplace, now what are you suggesting? I'm just trying to – maybe help me understand.

MR. CUTTER: Yeah, that's one step. I think in terms of presentation, having all of these on the same table does make it a little hard to distinguish across technologies, but the one next step, and where this kind of goes against what I was talking about before, is this issue of residual capacity value, particularly for a CT, you know, and that's the metric PGM and ISO used and was used in the DR proceedings, trying to do some quantification of how much revenue requirement is left over after a CT and perhaps a CCGT earn revenues in the energy and AS markets is a pretty common measure of capacity value. That might be a step beyond what you want to try and do in the IEPR.

MR. KLEIN: Well, would you be suggesting, for instance, I'm still trying to understand it, that that table be split in two?

MR. CUTTER: For example, I don't think a dollars per megawatt hour is ever a useful metric for a CT, so just not have that in the table at all.

MR. KLEIN: Okay.

MR. KUBASSEK: Well, I think – I'm just kind of throwing this out there – displaying total fixed cost is dollar per kilowatt year, and then your variable cost is dollar per megawatt hour. Both of those values won't change -- by those –- depending on your capacity factor. Zero or 100, your fixed cost will always be the same on a dollar per kilowatt year basis, and zero to 100 percent capacity factor, your variable costs are always going to be the same on a dollar per megawatt hour basis, unless you're – well, okay, so you're making assumptions about heat rate degradation or something, but that's – when we're talking about the grand scheme of things, the slope is going to be less of an impact, it's more illustrative, and then it prevents that issue, but I think that simply right there is having fixed costs and variable costs on different metrics kind of solves what the issue was for a CT or –

MR. RHYNE: Okay, any other comments? Okay, thank you. So, my next question is keeping it in a big picture kind of theme, so besides units of value, let's talk more specifically about what a levelized cost model, or a cost model produced by the Energy Commission, can or should include. We have traditionally focused on those costs that are kind of endogenous to the process of construction and operation, so what the owner of the generation resource will have to pay to build and operate the plant; but, as we've heard today, there is some discussion around using other costs, system costs, other costs that are exogenous to what the owner/operator, themselves, will have to pay out of pocket. We started some of that discussion a little earlier, and I want to throw it to the panel now to maybe continue that discussion. What other costs – or should any of those other costs be included?

MS. CHAIT: This is Michele. I'll reiterate what I said in my presentation. The system cost and LCOE costs are separate analyses and if you're trying to reflect what, say, the all in cost of one of these assets under a PPA is, it's inappropriate to include system costs such as capacity and energy benefits, transmission distribution benefits, integration costs, but those costs are appropriately included in a system impact type of analysis. Within E3, we used the Cost of Gen LCOE numbers as LCOE, and also get into the break-outs of the cost components that comprise the LCOE, and we find it a very useful study for that.

MR. MENDELSOHN: This is Mike Mendelsohn. I guess from an outsider's perspective, it's hard to know exactly how you're using this report. And perhaps you have many audiences and they're using it for different reasons. But maybe you really have to show both the LCOE and take a stab at the combined impact with the system costs, so that these resources can really be put on an even keel for evaluation of where we go with the portfolio.

MR. RHYNE: Okay, thank you.

MR. MENDELSOHN: Yeah.

MR. RHYNE: Go ahead.

MR. SILSBEE: If I could just offer a suggestion. This morning, I was struck by the equation in Ryan’s presentation, distinguishing ranking cost from generation cost. And one of the challenges, I think, that the CEC faces here is what really makes more sense for planning purposes and for understanding the tradeoffs that we have for planning the transmission, or generation system, is more along the lines of what RETI used as ranking cost. So we either try to get this model to be a player in that forum, or we go just the exact opposite way and almost make it a catalogue of just the data inputs, and then leave those data inputs to the user, such as yourself and ourselves, to interpret as they see fit. But this middle ground where we have a levelized cost of energy rank ordering that would appear to compare things like solar and wind and CT, but not do so on a truly comparable basis, I think, is an uncomfortable middle ground. It's hard to stay with just because of its potential for misleading people.

MS. CHAIT: I'd actually like to pose a question to SCE. How would you propose calculating system-wide costs of integrating a renewable portfolio on an individual asset LCOE basis? Because it's my understanding that you would look at a whole portfolio scenario, say, this trajectory case in the LTPP, or an economic basis, or timing basis, and you would look at the system cost of an entire 33 percent RPS portfolio on a system-wide basis, and I was just curious how you would propose to translate that to an LCOE analysis where different portfolios might have very different system costs.

MR. SILSBEE: It's a good question. And I don't have a good answer. I think at the level of understanding or granularity that we have today, wind and solar both create integration cost, but I'm not sure which one creates more. And it's going to take a lot of work to get there if we want to try to fine tune the estimates of integration costs between different kinds of resources -- a lot of work for people with big computers.

MR. CUTTER: Eric at E3, to add. Every estimate of integration cost, as I understand it, does look at it on a portfolio basis, which is really hard to then translate to an individual LCOE basis, but it would seem an appropriate, or dividing line, would be for the LCOE report to perhaps more clearly delineate itself as an LCOE in focusing on a PPA busbar kind of analysis, and then leaving the integration cost to more of the portfolio analysis currently done in LTPP or commonly done by the CAISO. You know, as an example, the simplest approach E3 was comfortable using was at least taking all the resources in the RETI zone and then adding up how much CT capacity was needed as a result. But all these analyses, there’s a lot of interplay between the portfolio and the level of penetration, for example, PV gets a lot less capacity credit 10 years from now than it does now because, if you assume a lot of PV on the system, the net peak, just later in the day, and all those kinds of factors just seem too complex to do in kind of a simple LCOE report without it then be caveated to the point where it becomes much less useful to a wide variety of stakeholders.

MR. RHYNE: Okay, thank you. I think we have a comment from online. Can we unmute? Okay, go ahead.

MR. MILLER: Hi, this is David Miller from CEERT. Can you hear me?

MR. RHYNE: Yes, we can. Thank you.

MR. MILLER: Yeah, hi, great. I wanted to comment that I just wanted to agree with the previous speaker that I think it would be really challenging to try and conflate the cost of the LCOE with system integration charges and I think one point that maybe should be raised right now is that the system currently socializes the cost to the system of contingency reserves, which are there to protect the system from an outage of the largest single generator, which in California is the nukes. So I think, you know, if you're going to start opening up the conversation about who should pay for the integration charges, I think it's important to recognize that the system is already paying a lot for integrating thermal resources and if we're going to bring that conversation out, I think maybe it makes sense to really look at it altogether, and not just to the renewables since they're sort of the last people to the party. But that's my comment. Thanks.

MR. RHYNE: Thank you. Any comments from our panelists?

MR. SILSBEE: I do want to be careful not to throw the baby out with the bath water here. The values we're talking about for renewable integration are, as you can see in the charts, not a very big chunk of the overall total costs, and it really – you have to tradeoff what are the objectives we're trying to accomplish here, and it's either, I think, moving back to a considerable retrenchment of what's in the report to break it up at discrete chunks, and they're only similar resources, and not to try to put CTs on the same chart as renewables, for instance; or, as to make some effort, admittedly not perfect, but nothing is perfect, to come up with a more meaningful rank ordering that may be more instructive. But, as I said, I think this middle ground we're in now isn't a very good place to be.

MR. RHYNE: Thank you. So that actually leads to – sorry, go ahead.

MR. BLAIR: This is Nate Blair. I was just going to add one thing, that I think that, following maybe on Mike's comment a little bit, but separating the LCOE calculation and tools and methodologies from the system calculation tools and methodologies is something that I would advocate because I think conflating them, as other people have indicated, you could end up with a result that is very very site specific and not as generally useful. But one thing that we've done at NREL that's helpful, I think, is that we work very closely with the teams that actually deal with the system analysis of say WECC or something, some large area, and I think that the focus could be on making sure that whatever tools are at the LCOE, or at the busbar PPA sort of level, as you mentioned, are really compatible and have consistent metrics, consistent definitions, and handshake very easily with the system level tools. Thank you.

MR. RHYNE: Thank you. Okay, so we’ve got another comment on line. Go ahead.

MR. MILLER: This is David Miller from CEERT again. I just wanted to make a quick comment, that I think that the work from Edison was real useful because it actually took a really nice look at what those charges to the system would be, so I think getting that kind of information on the table is a great thing, and actually, I’d like to see that explained more. Thanks, that’s my comment.

MR. RHYNE: Okay, thank you. Okay, so we’re going to shift gears just a little bit here. And this next question kind of refers to the graph that is up here on the screen, and that is the fuzziness or inherent uncertainty associated with so many of these cost estimates, especially when we began to look out into the future. It’s difficult to even get estimates, as many of the presenters have noted today, with regard to what’s just been built recently, so what’s actually been built, getting good cost estimates is difficult enough, then projecting those cost trends out into the future as some models, the CEC model, attempts to do so, but not all of them, adds a layer of difficulty. And what comes out of that is a great deal of uncertainty. And the bands that are demonstrated here kind of give us a sense of how large some of those uncertainties are.

I’m going to ask the panel, how can we, first of all, deal with kind of narrowing some of those ranges of uncertainty, if possible; but, second of all, how do we communicate that uncertainty best in the models? Because this is a really critical piece of communicating to policy makers. When we talk about costs, these costs especially for future projects that are not set in stone, and so helping policymakers understand what those uncertainties are is important to us.

MR. PLETKA: Yeah, I’d like to comment on that. This was an issue that I deal with every day, frantically, and it was a big part of the RETI assessment. I mean, I think it’s important for people to understand that, you know, estimates of renewables of fossil fuel are not points to begin with. I mean, if you had a chart up here which was the cost of homes in California, right, that would vary from $50,000 to $70 million or something like that. So, there is absolutely a range in these estimates and that should be reflected. One of the things that was a big issue in RETI was that there were a lot of people who were saying, “My technology, it’s commercial, but it’s getting even better every day and the costs are going to come down by such and such percent by this time, and you need to make sure that that’s included in the forecast.” And we get wrapped up in these things where we have to make cost forecasts out to 2020, and I hate doing that kind of thing because there’s no way you can be right, and no one in this room is going to sit here and tell me they can do it any better than anybody else because, you know, looking back just the last 10 years, I don’t think anybody could have predicted the pattern that power plant costs went through the last 10 years. The key thing I think that we came away with, and it sort of was a compromise in RETI, was we said, “Look, we’re trying to do transmission planning now.” We’re talking about $10, 15, 20 billion worth of investment that we need to start on today. Can you really say, you know, “Guarantee me, put that $20 billion on the line, that your reduction is so certain that it’s worth us really putting that much money on the line?” And the thing we came back to was, you know, all these things are essentially a combination of steel and wires and other things like that, and there’s a lot of commodity driven prices here, and none of us can say that such and such technology is so much better than other ones, or has so much potential for cost reduction that it really was going to have a dramatic difference in kind of its cost reduction potential over time, maybe with one exception and that was when we first looked at solar PV costs back in 2008, there was some recognition that there was probably greater potential there, but we still didn’t do a forecast of solar PV cost reduction, what we did was just kind of did the sensitivity study. So that was, you know, the uncertainty related to that cost, we essentially just wiped it out, we said within 10 years, everything is either going to get a little bit better or a little bit worse, and let’s not put that into our uncertainty bar because it would just make them huge. So we really tried to focus on – I think there were two types of uncertainty – one is, when you do a site estimate, you know, there are some things related to the site that, if you put PV panels on a farmland, or you put them on some other type of rolling terrain or something, there is going to be site-related costs that are definitely going to cause differences. So when we make point estimates, we have to understand there is that sort of site-related uncertainty and that’s always going to be there. And there’s also just the general uncertainty of, “Is my answer the right one?” You know, “Do I really know the cost is this, related to escalation and inflation?” So there’s sort of like these multiple levels of things that you need to understand. And when we did RETI, we kind of said, well, let’s just pretend that we’re right and let’s just try to focus on the uncertainty that really differentiates one area of the state from another so we really focus on that kind of site-related uncertainty when we made our estimates and that the bands for uncertainty we still had, I thought, were huge, but they were meant at the end of the day to reflect the uncertainty that decision makers needed to be aware of, at least in my view, things that there was some level of real uncertainty related to site, enough that everything was going to be plus or minus – plus 20 percent or minus 20 percent, it was one area of the state was better than another and that was, I think, what we tried to communicate.

MR. SILSBEE: Some of this uncertainty is just simply reality, one developer vs. another developer may encounter different costs, or may have trouble with permitting environmental restrictions and so forth, so I think it is appropriate to show bars such as you have here. I suspect from looking at the wide range of some of these numbers that there’s, you know, convoluted with construction cost uncertainty, you may have different technologies, or perhaps different capacity factors that are included in the range and I think there are other ways to deal with those variations besides treating them as uncertainties. I think that the stuff that Justin presented which showed a screening curve as a line could be turned into not a line, but maybe a range of values and similarly the dots in that curve for the intermittent technologies could be turned into bars, so I think there are ways to portray the data that do reflect some of those underline uncertainties, and I would encourage that.

MR. KLEIN: By the way, I think we did screen up capacity factor difference, right? In developing our cost, at least for the gas-fired units, because we developed component cost for installed cost and –

MR. SILSBEE: It’s hard for me to imagine that the range of cost on a simple cycle combustion turbine is 10:1.

MR. MCCANN: Well, some of that was – there was actually uncertainty about the capacity factor and it was, for example, in the merchants, there was – I think it was five percent and range at least at 10 percent, which causes a 50 percent swing right there. And so I think that uncertainty is in there. And then, for some like wind, I know that wind was like centered around 34 percent, but at four percent either way, so there is a capacity factor uncertainty in there.

MR. KLEIN: No, Richard is right, I mischaracterized that. We had to assume for the purposes of those bars a range of capacity factors. I was thinking back to the original data being muddled. I misunderstood you, but, yes, we have ranges of capacity factors, 2.5 percent to 10 percent, or something like that, I can’t remember. Yes, that’s a big driver there, absolutely. I apologize.

MR. RHYNE: Okay. Any other comments? Richard.

MR. MCCANN: I don’t know if you’ve moved on to it, I had a question about how to treat uncertainty about tax policy because, if you look at ARRA is expiring, is now going to start expiring over the next four years, a number of the other tax benefits come up for renewal, some usually get renewed, but other ones are less likely to get renewed, and particularly in the political environment we have in Washington, D.C. right now, it’s even more uncertain about tax benefits. And we attempted in the Cost Generation Model to deal with that explicitly because it's a one-zero type of uncertainty. How do we deal with that kind of uncertainty going forward? And it clearly has a very big impact on cost, that type of uncertainty.

MR. KLEIN: I don't think I made that clear before, but for our model, we assumed existing expiration dates for the ITC, whatever they were. Like on the property tax, we presumed that would be – for solar – property tax exclusion for solar – we assumed that would be ongoing, but for the ITC, we assumed that they expired when they were presently delineated to expire, and that was like 1013 for wind, 1016 for solar, and everything else was – I said that wrong – 2013, 2016 for solar, and 2014 for everything else.

MR. SILSBEE: This raises a broader question, which is what does the snapshot today look like vs. what might the snapshot five or 10 years from now look like? And if you look at one of the presentations that Joel put up earlier today, it showed a very significant forecast of declining prices in several of the solar technologies. That creates, I think, some very difficult questions. If we think that, well, let me just frame it generally, if you have Technology A and Technology B, and Technology B is more expensive today than Technology A, but you think Technology B is going to be cheaper in 10 years, then maybe you shouldn’t build – you definitely don’t build Technology B today, but maybe you don’t build Technology A, either, if you can afford to wait. So, what we’re doing here when we see these choices, we create some optionality, that it might be better to hold back on the capital until the uncertainties are resolved. Those are very tough judgments. My recommendation would be to run the numbers based on what’s on the left side and, if you want to do some sort of a separate calculation of what things might look like five or 10 years hence, then run that as a completely separate piece of the analysis.

MR. KLEIN: Well, we did have two target years that we used, one was 2009 and one was 2018. But I see you point. Could you possibly be suggesting that our consultant missed any of those numbers if they weren’t exactly right? Are you suggesting that? I would think a consultant, I’m sure, got that right. How could they miss?

MR. SILSBEE: No, I wasn’t critiquing the numbers themselves, I was addressing the issue of the uncertainty of any forecast.

MR. KLEIN: I’m just glad I didn’t have to do that.

MR. PLETKA: When we do these types of studies, long-range things, and we look at the tax credits, usually it’s – we do a case with and a case without. What I think is probably the case – and when we do that case without, if we’re doing like what we think the picture is going to be in 2020, it’s not that we say, “Okay, we now have a 30 percent tax credit that goes away in 2016, and so we don’t have anything for renewables.” Typically, we’ll say, you know, what is a constant, I think, is that there’s a strong political commitment to low carbon technologies, be they renewable or whatever, and that if we do run out of a tax credit, we no longer support renewables that way, perhaps there will be a national or Federal, you know, a strong CO_2 policy, that will provide some other type of incentive, you know, if we don’t have an ITC, maybe there will be a stronger PTC. Who knows what it’s going to be? So, generally, it’s not like a cliff happens in 2016 and all of a sudden, if you don’t have you renewable plant developed by then, you may as well leave the country. We’ve got some kind of assumption of ongoing policy support of some form, it’s just we don’t necessarily know what it is.

MR. RHYNE: All right. Thank you. So the next question is about updates and triggers for updates. I’m framing the question on the assumption that the CEC continues to revise this model that's not a given, necessarily, we're open to doing things differently – completely differently, in fact. But, whatever model we do, what would be the trigger for doing a revision or an update? Is this something that, from your point of view, this just kind of a broad model should just be every couple of years because of the kind of fluctuation of market conditions? Should it have specific triggers for updating? Or should there be some other mechanism for deciding now is the time to go back, review these costs, and try and capture them going forward? And the silence is deafening.

MR. MENDELSOHN: This is Mike Mendelsohn from NREL. I would think a bi- or triennial analysis would smooth out the fluctuations that you're definitely going to see. I mean, that's where gas prices spiked, by the time you got your report out, they'll probably come back down, or vice versa. So, I would think you just have got to take a snapshot in time and do the best you can with the information you have at that moment.

MR. RHYNE: Okay, thank you.

MR. MENDELSOHN: Thanks.

MR. SILBEE: I'm generally comfortable with the every other year process that the CEC seems to be undertaking. I hate to see a lot of make work and I think moving to annual might be more work, or more cost than is really justified here. I think the fact that the model is publicly available and a user can come in and put in their own inputs, if they believe some particular element of the input data is stale, makes it far less important to update on an extremely frequent basis. I think we are seeing a lot of changes in technology cost, there's a lot of changes in the renewable energy market in California, for instance, so maybe about every couple of years make sense. At some point in the future, I could see the CEC concluding that things aren't moving as fast and maybe you can bump the cycle back.

MR. PLETKA: Yeah, I talked earlier this morning about this product that we put out every six months and I think the frequency for that works well for us and captures these fluctuations that are happening. I think it is dependent upon kind of like what you were saying, you know, are things changing or not, and things are changing a lot now. So, I mean, right now our report on Cost of Generation from 2009 is – it's actually somewhat still relevant, but maybe the year 2007 stuff was, by the time 2009 rolled around, really out of date; and in some respects, the 2009 stuff is just not a worthwhile reference anymore just because things have changed, everybody knows things have changed. So six months works well for us, but our burden of work to put our six-month change things together is really pretty small compared to what you had to do here, so, you know, I’m not sure I gave you –

MR. RHYNE: No, actually it does. But it does lead to a follow-on question. So, how would you compare the end use for that every six month revision of that product to the end use of, you know, a big kind of robust model and data kind of validation effort on the part of an organization like the CEC? And are they really comparable in that sense?

MR. PLETKA: Yeah, I think they are and they aren’t. I mean, there are certain inputs probably within your product that you produce that people are really looking for, you know, what do simple cycles cost and what are solar PV? But people are probably not going to want to knock on your door every year to determine what the latest cost for biomass ITCC is, you know, so there are certain elements maybe within your thing that you could say, “Now, this we need to look at more often.” But, you know, gas turbine O&M costs? You can probably let that slide for a couple years. Solar PV capital costs? Maybe you should look at the more rapid refresh on some of this stuff.

MR. RHYNE: Any other comments?

MR. MENDELSOHN: This is Mike Mendelsohn again. It would be interesting to get this projection of forecasted prices against actual results and, I mean, if you could highlight bid prices, or perhaps some client prices from other market data, to make sure that you're really right in the zone of what the market says. I mean, in the end, it really comes down to how the market really responds to be able to provide these resources. I mean, I assume that you're just using this to sort of feed your RFPs and how you evaluate resources on a competitive basis, but I'm not completely sure on that.

MR. RHYNE: Right, so – and I apologize if I didn't set the context quite sufficiently, but the Energy Commission really doesn't issue or oversee RFPs for generation resources, instead, we have kind of a key role in formulating long term energy policy for the State of California, and the Public Utilities Commission, our sister Commission, oversees the procurement aspect of generation resources for the investor-owned utilities. And so, these cost estimates are used by a wide variety of stakeholders, many of which are external, some of which are internal, for the purposes of understanding how different policy choices affect, you know, possible future scenarios within the state. And so it’s not a nice clean and clear, you know, “Here’s our end use that it feeds into all the time.” It’s a little more broad in terms of feeding our thinking on a wide variety of issues.

MR. MENDELSOHN: Right, and that’s what I imagined. But, yeah, it would be great to be able to compare the work you do here to how the market is saying, you know, responses to investor-owned utility RFPs, or what have you, that are relevant just to really inform the process.

MR. RHYNE: All right, thank you.

MR. BLAIR: This is Nate Blair. I had one more quick comment on the periodic nature of updates and I think one thing that could be helpful is – is just assigning more work – but is to have some discussion in the documentation and the model itself about the responsiveness to commodity prices in the individual technologies, and I apologize if that’s already in there, but I think at NREL we’ve done some work with – we have older cost estimates that, you know, how do you update those in the next intervening couple of years, and certain technology cases that, you know, the big drivers are really these massive increases in commodity prices. And I think in terms of how you deal with these numbers in the intervening years, that’s obviously one of the big drivers. Thanks.

MR. RHYNE: Okay, thank you. All right, so I've just got a couple more questions. The first is that we produce a large list of technologies that we cover in our report. That list, as has been noted, I think by Joel and by others, is pretty time and resource intensive to make sure that we've captured all of the relevant issues associated with them. And, in fact, if you go out to our 2018, we include technologies there, I think offshore wind being one of them, that aren't currently kind of on the radar, or being physically built today, but could be if you go out five or 10 years. So, the question to the panelists is, is there a subset of these technologies that we really should be focusing on? Or, conversely, are there any technologies that we really should just let go from this analysis and spend the rest of our resources on focusing on the remainder?

MR. KLEIN: Why don't you put our list up that we – the table I had before? The table of levelized costs. Because I don't know offhand if everybody knows what that list –

MR. RHYNE: Here it is.

MR. KLEIN: Can you blow that up at all? It's a little hard to read.

MR. RHYNE: All right, so I think that’s our list there.

MR. KLEIN: Later on, like I said, we have nuclear was on our –

MR. RHYNE: Yeah, so we have a next generation nuclear power plant and an offshore wind, I think both of which get added in 2018 for this list.

MR. PLETKA: Yeah, I think you have too many. I went through the exact same process. You know, for our products thing, we had a whole list of potential things that was as long as yours plus a whole bunch of energy storage things, wave energy, tidal energy, all this stuff, and we came down to what do we think our end users for our product would be most interested in, particularly on the six-month update kind of cycle, and it’s probably half the number of technologies that you have. We do have two simple cycle, you know, a frame machine and aero derivative, a single combined cycle, a coal unit, and you’ve got a coal unit, right, IDCC, one biomass technology, I mean, I don’t think there’s really any difference between fluidized and stoker in terms of capital costs, and one geothermal. So we sort of like get it down to probably about 10 technologies, maybe it is. And it makes it much more manageable and I can understand how you might want to like include some of these potentially advanced technologies as an interesting thing because maybe we should encourage those, perhaps they would just be done every other time you update things, or it might be a special study or something like that.

MS. CHAIT: I'd like to add also that it might be beneficial, given this is California and there is quite a bit of solar procurement that you add, a breakdown for fixed and tracking solar PV and also for solar thermal with and without storage. So, maybe add a little additional granularity on those resource types if you're removing some of the others.

MR. PLETKA: Yeah. We do the same thing. That would be good.

MR. RHYNE: Okay, any other feedback?

MR. SILSBEE: The concern we have had in the CTs is just the labeling of small conventional and advanced, and I think greater clarity on what the specific technology is would be helpful to us to better understand the cost estimates. I do agree that there's probably some reason to, on an ongoing basis, try to trim the list to take things out that just don't seem realistic in California. What you may find is you're adding as many as you're taking out, though, just because of the interest in looking forward to things such as the potential for the mix in storage with the solar facilities.

MR. RHYNE: All right, thank you. So the last question that I have for you for the day, and actually, you know, I'm going to hold off, are there any other comments or questions from folks in the audience or folks online before I hit everyone with my last question? Going once?

MR. NELSON: Yeah, I have one question.

MR. RHYNE: Go ahead.

MR. NELSON: This is Ken Nelson with Element Markets. Just to re-touch on that one question that a previous – somebody else brought up here just a bit ago regarding the CPUC and the CEC's – how this actual modeling will be used. Is there any attempt to harmonize the models between the two groups or just to try to get a sense of some of these concepts that are coming out in this discussion are very relevant, but I would be interested to know if there is an attempt to harmonize the application.

MR. RHYNE: Yeah, so, this is Ivin Rhyne again. I think the word "harmonize" could be – you could read a lot into that. I think there is a great deal of effort going on right now to make sure that what we do in terms of a levelized cost model, or a cost model however it is ultimately presented, is consistent in principle and to whatever extent is reasonable and also in application, with the work that is done at the Public Utilities Commission, and that it actually is useful in proceedings, both internally and externally there at the Public Utilities Commission. To say that they will ever be completely 100 percent harmonious, I think, would perhaps kind of undermine the two very different, or slightly different, at least, purposes of the organizations where we work in tandem, but we kind of have different roles with regard to, you know, moving forward in energy policy in the state. So, to the extent that it is practicable and reasonable, we will absolutely be trying to harmonize and align with the work that is being done at the PUC.

MR. KLEIN: This is Joel Klein. I have one more qualifying comment. One of the problems that we've had in the past is the CPUC would ask us for an assumption or something, and the timing just wasn't right that we could provide it to them at that time, so timing is always an issue in these things, having the right data at the right time, but we do try to work together and, wherever they can, I notice the CPUC will use our assumptions.

MR. NELSON: Okay, thank you.

MR. RHYNE: All right, thank you. Any other comments or questions online? All right, looking over to my technology guys, they're both kind of shaking their heads.

So with that, I'm going to kind of wrap up with a big question to the panel. And I've kind of alluded to this previously, that the Commission is looking broadly at the approach that we have used in the past with regard to estimates in modeling generation costs, specifically for new generation technologies. Given that we are moving forward and trying to formulate and form energy policy in the state, do the panelists have any specific comments or questions – really, comments or suggestions, I should say, about whether or not the CEC should be doing an incremental change to the model as it stands today, or should we be fundamentally revisiting this model and kind of starting from scratch in other ways in attempting to capture some things fundamentally different about how we approach this question?

MR. KUBASSEK: Our recommendations are purely – are designed to be just incremental, so I don't think we would say go completely revamp your model. What we're recommending, I was just looking at these additional implicit costs that just haven't really been thought of before, about how to even approach them within a levelized framework, and as a resource for informing policy, putting these issues out there, I think, is valuable, especially as we're trying to move the state forward.

MR. SILSBEE: I'll just point out that Paul Joskow, who is a noted economist from MIT that works quite a bit in the electricity industry, did a paper a little while ago commenting about the misleading nature of LCOE analysis and suggested that it be replaced with more of a cash flow type approach, similar to how developers would look at the economics of a project. We're mindful of that suggestion. What we've tried to do is mirror it with incremental changes because we think there is such a degree of utilization of levelized cost models in the industry that it would be hard to just throw them out completely. I think there is value to making changes to capture some of these indirect costs. I think if the CEC were to abandon that kind of effort, there would be other people out there who would continue to use levelized cost of energy models without the caveats or the asterisks. So I think there is an opportunity for the CEC to take a leadership role here and try to advance the state of the technology and, in doing so, educate people on how best to think about comparative generation costs.

MR. RHYNE: Thank you.

MR. PLETKA: My view is I think maybe just some incremental changes, I think, in line with the other comments. Today I would support simplification more than anything else, and tightening of what it is you're trying to do, and do that as well as possible, as well as you possibly can. The kind of overarching comment, I mentioned it this morning, but it's still surprising to me that there's not, within our nice country that we have here, one reputable source of real good cost of generation information that – there are a lot of people working on it, but it's sort of surprising, I guess, that the CEC feels that it's its responsibility to make sure that you can put out something that you can rely on. We've got the Department of Energy doing their thing and EPRI does their thing, and there are all these different sources, and whenever you look at anybody who puts out cost of generation information, you try to figure out where is it really from. So, I don't know if there's some way that the CEC and the folks here from NREL can work to have a more robust dataset that we can rely on nationally. And, even, I was looking at some stuff last week and, you know, the IPCC, the Intergovernmental Panel on Climate Change, looks at information like this and they were looking at some data from 2007 for biomass policy which was just way way out of line. There needs to be a better, more reliable source of this type of information, and I think the CEC could definitely play a part in that. So, that’s my suggestion.

MR. CUTTER: Just continue going around the table. Also, there’s a lot that’s valuable in the current report and model and Mike was advocating before, I think, that incrementally changing that and focus on what it can be used for and done well, rather than trying to do a wholesale change and capture a whole bunch of these other goals that various models might espouse. But I would say that the detail that is in the model is often very helpful. The CEC reports the only good one I know of that really gives you a flavor for different heat rates and heat rate degradation and a good reputable source – Joel, in particular, has done an admirable job of understanding all the NERC criteria and all these different rates and how to interpret that in the results. And so there’s a lot of useful – it’s very useful having the detail available either in the model or in the appendices of the report, so I don’t want to get too simple. From the point of view of working an awful lot with the CPUC and using or not using inputs in the Cost of Generation Model, it always comes back to --

in any of these proceedings -- the numbers that eventually get used are ones that make some intuitive sense, either to the stakeholders, or to their real world experience, and I know, as much as Richard and Joel have tried to argue that their survey of actual plant data is the best source of data, and I think there is a strong argument for that being the case, you can never get very many people at the CPUC or that stakeholder group to get comfortable with the fact that a CT had a higher capital cost than a CCGT on a per Kw basis. That just ended up being a non-starter. As much as the data may have presented that. I think some outreach could help that. You could get a limited set of participants at the hearings up here at the CEC. We worked an awful lot on this Cost of Generation Model, having no input from a developer for many years, same at the MPR. So I was very glad to have Michele’s experience finally get put in here. So, perhaps more one on one outreach, somehow. But getting that real world experience reflected makes it more useful and having all the justifications in the world and rationale for having a different assumption, I’ve just found, never carries water in a public proceeding like someone just saying, “Well, historically they’ve run at 60 percent.” And even though we know that’s not right, that carries a lot of weight, that there's historical data out there. So, that's a long way of saying, 1) keeping a lot of the detail is very useful, but trying to have results that mirror what people are seeing out in the world and are using in the various proceedings helps to get used and not just dismissed out of hand, as robust as the survey or calculations are. I guess I would also add that the 2009 update to the 2007 that gave a lot more detail on the survey of plants was also extremely useful.

MR. RHYNE: Good. Thank you.

MS. CHAIT: Yeah, I guess I definitely agree with Eric. We refer to not only the data in the tables, but also the back-up data that has the heat rates and capacities and thing like that, so retaining all that data is extremely useful. I also agree with everybody else that a whole-scale revamp of this model is absolutely not necessary, and I think that some focused additional information with respect to certain of the technologies could provide a little bit more detail on those and potentially we find some of the cost estimates like cost of capital, capital costs, and potentially some tax ranges, I think that you'd be able to produce a really robust next version of the Cost of Gen Report.

MR. RHYNE: Good, thank you. Any comments from our participants online?

MR. MENDELSOHN: It seems that a large percentage of the discussion today was regarding to what extent and how to include system impact costs as a part of the metric or as a secondary metric, and it seems that, to the extent you were to revamp the model, it would be to incorporate those types of costs. I guess considering that most likely requires a production simulation effort, it's probably best to do outside of this model and, you know, through thorough analysis include it as an input or a series of inputs into this model. That being said, I guess it's how properly to evaluate those system impact costs and refer to them, and who to rely on to run those models because, traditionally, you have the utilities that have that capability, I don't know to what extent the CEC has that capability, but – NREL does, as well, but I would think there would be a need for sort of a solid working group among the stakeholders to get a better understanding of that key input.

MR. RHYNE: Thank you.

MR. MENDELSOHN: Sure.

MR. RHYNE: All right, any last comments either online or from inside the room? We've got one. If you will come to the podium?

MR. BECK: I'm Curt Beck. I'm from the Board of Equalization in the Property Tax Department. And I just want to say that we value the report and relate it – we use the capacity factors, heat rates, and some of the ERC information that Joel has provided in the past and we find it very useful. And as far as cap rate information, you're welcome to provide any input in every February. Thank you very much.

MR. RHYNE: Thank you. All right, any other comments? All right, and with that, I want to thank our panelists for participating and Al will wrap us up and see us out the door for the day. Thank you very much.

MR. ALVARADO: Well, there's really not much more I can really say here. I do appreciate this discussion. When we initiated this Levelized Cost of Generation Study, which goes back to 2003, we really had some very modest beginnings in our intentions. Initially, pre-deregulation, we used canned black box models and I think it was like FAS 123, or something like that, but our original intention was to come up with an easy to use, transparent tool, but our mission has sort of evolved since then, you know, questions about evolving technologies, getting a better understanding of the main cost drivers, you know, what will change in the future, but we've also tried to field numerous questions about comparative costs. And we've encountered folks that would pick the results of one study or the other without really understanding what underlies a lot of the assumptions. And if there are any sort of common boundaries between the assumptions, we really want to sort of weave a thread through a lot of the technologies that have very common variables.

As we discussed today, we're ready for our next evolutionary step, trying to go to the next level. Levelized cost is – I have always considered it just one of many building blocks we engage in resource planning efforts. There were suggestions about – we do have production cost models, so I don't know if there is a way of sort of merging some of these cost estimates with total system cost evaluation of portfolio costs and ratepayer impacts, but I think we have a lot to sort of chew on after this discussion here.

In terms of next steps, we would really welcome any written comments if there is anything else, at least our panel members have, to supplement what you've already provided to us, or if there is any other workshop participants or stakeholders, we're open to receive comments. We're asking if you can submit those comments to us by May 31st and we have details in our workshop notice in terms of where to send it to us.

Also, as a follow-up to what Ivin initially said, we are – nothing is really set in concrete here in terms of a project plan, and so we're going to bring a lot of this discussion forward to our management and our Commissioners, and examine really what is going to be a next step. Ivin indicated maybe let's shoot for an update cycle instead of right in the middle of an IEPR cycle; that way, we'd have – if we do come up with any cost updates, we're ready to apply those costs when we engage in our resource planning studies.

So, with that, I do appreciate the discussion. I really appreciate the participation. I know that some of you worked really hard to send our slides until very late last night, even. Thank you. And thank you, everyone else, who has participated. With that, the end of the workshop.

(Adjourned at 4:11 p.m.)